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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. U 39 M	Application No. 19-11-019 (Filed November 22, 2019)

JOINT MOTION OF THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, CALIFORNIA SOLAR AND STORAGE ASSOCIATION, ENEL X NORTH AMERICA, INC., ENERGY PRODUCERS AND USERS COALITION, FEDERAL EXECUTIVE AGENCIES, OHMCONNECT, INC., PUBLIC ADVOCATES OFFICE AT THE CALIFORNIA UTILITIES COMMISSION, SMALL BUSINESS UTILITY ADVOCATES AND PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), FOR ADOPTION OF JOINT SETTLEMENT AGREEMENT ON REAL TIME PRICING ISSUES INCLUDING STAGE 1 PILOTS

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I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California (the "Commission"), the Agricultural Energy Consumers Association ("AECA"), the California Large Energy Consumers Association ("CLECA"), the California Solar and Storage Association ("CALSSA"), Enel X North America, Inc. ("Enel X"), the Energy Producers and Users Coalition ("EPUC"), the Federal Executive Agencies ("FEA"),[1/] the Public Advocates Office at the California Public Utilities Commission ("Cal Advocates"), the Small Business Users Association ("SBUA") and Pacific Gas and

1/ The California Solar and Storage Association ("CALSSA") and Enel X North America, Inc. (Enel X) are two separate parties who have each been active, regular participants in the RTP settlement discussions. Although an entity called the Joint Advanced Rate Parties ("JARP"), then comprised of CALSSA and OhmConnect, had previously served testimony on November 20, 2020 (JARP-01), JARP does not seem to have made a party appearance. CALSSA and Enel X have since clarified that their May 28, 2021 responsive testimony (Exh. CALSSA-ENELX-01) supersedes the prior JARP testimony. CALSSA and Enel X have stated that they only intend to move Exh. CALSSA-ENELX-1, served May 28, 2021, into evidence during hearings in this proceeding, and not JARP-01 served November 20, 2020.

Electric Company ("PG&E") submit this joint motion in Application (A.) 19-11-019, to respectfully request Commission approval of the Settlement Agreement ("SA") attached hereto as Attachment A.[2/] [3/] The SA resolves all of the issues included within the scope of this track of the above-referenced proceeding related to program and rate design issues for Stage 1 Real-Time Pricing (RTP) Pilots ("Stage 1 RTP Pilots"), as well as a separate, but parallel, Customer Research Study for residential, agricultural and small business customers.

As discussed in greater detail below, the SA specifies the Settling Parties' agreement regarding: the Stage 1 RTP Pilots eligibility and enrollment, participating optional rates with RTP for the generation component, terms on inclusion of Net Energy Metering ("NEM") customers, pilot duration, interim evaluation and Advice Letter process after one year of pilot operation, final evaluation and Advice Letter process, RTP pricing dissemination, real time rate design, use of Energy Cost ("MEC") and Marginal Generation Capacity Cost ("MGCC"), MGCC Study process, design of revenue neutral adder ("RNA"), treatment of revenue requirement changes between GRCs, price protection, customer incentives, marketing, education and outreach ("ME&O"), dual participation between RTP and other dynamic rates/demand response programs, reporting metrics, measurement and evaluation ("M&E") reports (interim and final), and a Customer Research Study of agricultural, residential and small business customers' preferences regarding dynamic pricing (including RTP). The SA also addresses additional terms for participation by customers on Net Generator rates, generation revenue over-collection and under-collections (revenue requirement recovery and avoiding double collection), information technology billing systems changes and timing, as well as Appendix A to the SA

2/ Pursuant to Rule 1.8(d), the above-listed Settling Parties have authorized counsel for PG&E to submit this motion on their behalf.

3/ Other parties that did not actively and regularly participate in the RTP settlement discussions have been provided with the Settlement Agreement and have indicated they have no objection to it. In addition, the sponsoring Settling Parties are fairly reflective of the affected interests. Therefore, the SA satisfies the Commission's criteria for being considered an all-party settlement. (*See* D.92-12-019, 46 CPUC2d 538, 1992 Cal. PUC LEXIS 867, p. *9 and D.90-08-068, 1990 Cal. PUC LEXIS 1471, pp. *41-*42 and *49.)

providing further background and agreed conceptual details of PG&E's revenue requirement over-collection and under-collection study.

The Settling Parties are pleased that their intensive negotiations over the past year have successfully resulted in the attached SA, which they are proud to now be presenting to the Commission for its approval, without modification. The SA resulted from over twelve months of earnest, good faith negotiations, which included hard-fought exchanges that ultimately resulted in the SA's carefully balanced compromises. RTP raises many novel and quite complex issues, including about the technologies and systems needed for implementation. Specifically, the process of developing the Stage 1 RTP Pilots was made more difficult by the fact that the necessary underlying technologies and management methods, especially for the residential customer class, are still at a relatively early stage of development and market adoption. Although the Commission did not approve an RTP rate for PG&E like the one in the SA until Decision (D.) 21-11-017, these year-long discussions were informed by a careful analysis of the EPRI benchmarking study of existing RTP rates offered by regulated utilities nationwide, attached to PG&E's March 29, 2021 testimony. During negotiations, the Settling Parties also carefully considered concerns about price volatility (which is an inherent feature of RTP). On the one hand, if successful, RTP could eventually result in reduced costs for all customers (even non-participants) through reduced generation capacity costs. On the other hand, RTP rates carry with them potential for revenue requirement under-collection or over-collection that could result in cost-shifting and potential rate affordability impacts for all customers. Balancing these and other factors were all part of the Settling Parties' negotiations throughout 2021, through which they hammered out a balanced and reasonable approach to Stage 1 RTP Pilots and associated Customer Research Study. The resulting SA is designed to gather important information that should be useful to inform CPUC proceedings in the longer-term about dynamic pricing, including RTP.

The SA is a comprehensive, integrated, and unified package that the Settling Parties believe resolves all of the issues in the RTP track of PG&E's 2020 General Rate Case Phase II

(GRC Phase II) proceeding, reached among all of the parties actively and regularly involved in the RTP track of this proceeding. The SA's outcomes fall within the various positions of the parties, and were based on well-thought-out and careful trade-offs that, when combined into this overall integrated package, result in a sound plan for PG&E's Stage I RTP Pilots and Customer Research Study.

The Settling Parties believe that the SA fairly balances the various interests affected in this proceeding. The SA satisfies the criteria for Commission approval, in that it is reasonable in light of the record as a whole, consistent with law, and in the public interest. Accordingly, the Settling Parties respectfully urge adoption of the SA in its entirety, without any modification.

II. BACKGROUND

The RTP issues being considered in this phase of PG&E's above-captioned GRC Phase II proceeding, follow litigation and Commission decisions on the main marginal cost, revenue allocation and rate design issues considered in the main track of this GRC Phase II, which resulted in D.21-11-016 (as well as D.20-01-021 on an earlier expedited track that established the parameters of the Essential Usage Study for the three major investor-owned utilities in California). The prior procedural history in A.19-11-019 was set forth in Section 1 (pages 2 through 6) of the Commission's recent GRC Phase II decision for PG&E, D.21-11-016.

The RTP track of A.19-11-019 stemmed from an August 27, 2020 ruling, of then-assigned Administrative Law Judge (ALJ) Doherty, clarifying the procedural schedule and inviting parties to provide testimony on RTP rate design issues for consideration in this proceeding. That ruling specified the following deadlines for submittal of RTP testimony, with Cal Advocates' deadline October 23, 2020, and other intervenors by November 20, 2020, followed by rebuttal testimony from all parties by February 15, 2021. Cal Advocates timely served its RTP testimony on October 23, 2020 followed by RTP testimony served November 20, 2020 from three other intervenors: AECA, SBUA, and CALSSA and OhmConnect (jointly referred to as the Joint Advanced Rate Parties (JARP)).[4/]

In November and December 2020, two motions were filed seeking to consolidate the RTP rate design issues with a separate Commission proceeding considering RTP structure for certain PG&E electric vehicle charging station operators (A.20-10-011). Both motions were denied. However, several parties jointly filed a motion on January 27, 2021, seeking to bifurcate RTP rate design issues from the other marginal cost, revenue allocation and rate design issues in this proceeding, and consider them on a delayed track that would allow for complementary consideration of issues arising in A.20-10-011.[5/] That motion was granted on February 2, 2021. The bifurcation of the RTP issues required a revision to the procedural schedule, and an Assigned Commissioner's Amended Scoping Memo and Ruling was filed on February 16, 2021, including the following new dates for submitting testimony on RTP issues: March 29, 2021 for PG&E's opening testimony, May 28, 2021, for intervenors' responsive testimony, and July 30, 2021 for parties' rebuttal testimony. Accordingly, on May 28, 2021, three responsive exhibits were served, respectively, by: Cal Advocates, SBUA, and CALSSA-Enel X. On July 30, 2021, seven rebuttal exhibits were served, respectively, by: Cal Advocates, CALSSA-Enel X, CLECA, EPUC, FEA, PG&E and SBUA.

Ongoing weekly settlement meetings began on January 15, 2021. Over 30 such weekly meetings had been conducted as of mid-January 2022 with additional *ad hoc* meetings conducted as needed, to allow delegated subgroups to make progress between weekly meetings on specific topics (such as MGCC, RNA rate design, as well as whether a potential third pilot rate should be included and if so what rates to select). Although 16 parties participated at some point during these weekly RTP settlement meetings, 10 of these parties, listed above, attended on a regular

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4/ Please see n. 1, supra, which explains that this testimony was superseded by later responsive and rebuttal testimony served by CALSSA-Enel X on May 28 and July 30, 2021, for which clean and redlined errata was served on January 10, 2022.

5/ A.20-10-011, known as PG&E's Commercial Electric Vehicle RTP pilot rate proposal (DAHRTP-CEV Pilot), was decided by the Commission in D.21-11-017.

basis, actively participated over the past full twelve months of settlement discussions, and have signed the SA (Settling Parties).[6/]

In a Second Amended Scoping Memo and Ruling dated August 25, 2021, the Assigned Commissioner set hearings on RTP issues for January 24 to 26, 2022. Although PG&E had sent a July 30, 2021 notice for a meet-and-confer conference intended to be held on August 9, 2021, the ALJ subsequently allowed the meet-and-confer date to be delayed once hearings were set for January 24 to 26, 2022. Accordingly, PG&E re-noticed the meet-and-confer conference to November 17, 2021, when it was duly held. On December 22, 2021, Assigned ALJ Sisto issued an Email Ruling Confirming the Date and Time for Evidentiary Hearing and Providing General Guidance and Instructions in Advance of Remote Hearing. On January 6, 2022, pursuant to Rule 12.1(b), PG&E filed and served on all GRC Phase II parties a Notice of Settlement Conference, that was held January 12, 2022 at 3 p.m. Thereafter, the Settling Parties reviewed this Motion and executed the Settlement Agreement that is provided herewith.

III. THE SA IS REASONABLE IN LIGHT OF THE ENTIRE RECORD, CONSISTENT WITH LAW, AND IN THE PUBLIC INTEREST

The Commission has acknowledged "California's strong public policy favoring settlements," pointing out that "[t]his policy supports many worthwhile goals, such as reducing litigation expenses, conserving scarce resources of parties and the Commission, and allowing parties to reduce the risk that litigation will produce unacceptable results."[7/] The Commission's policy of favoring the settlement of disputes "supports many goals, including[:] reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce

6/ Six Parties attended at least one Settlement Meeting and do not oppose the Settlement Agreement: Center for Accessible Technology (CforAT), California Manufacturers and Technology Association (CMTA), Direct Access Customer Coalition (DACC), Joint Community Choice Aggregators (JCCAs) and The Utility Reform Network (TURN). Four parties did not file testimony on any of the issues addressed in this Settlement Agreement and did not participate in settlement discussions: California Farm Bureau Federation (CFBF), Natural Resources Defense Council (NRDC), Sierra Club and Solar Energy Industries Association (SEIA).

7/ D.11-05-018, p. 16.

the risk that litigation might produce unacceptable results."[8/] In evaluating a proposed settlement, the Commission will apply the test set forth in Rule 12.1, which requires that the settlement: (1) be reasonable in light of the whole record, (2) be consistent with law, and (3) serve the public interest. The Commission takes a holistic approach to considering proposed settlements, weighing the entire agreement as a whole rather than assessing just its individual parts:

> In assessing settlements we consider individual settlement provisions but, in light of strong public policy favoring settlements, we do not base our conclusion on whether any single provision is the optimal result. **Rather, we determine whether the settlement as a whole produces a just and reasonable outcome**.[9/]

As discussed below, the SA fully meets the criteria set forth in Rule 12.1. The SA reflects a compromise among parties of diverse interests and positions, that are fairly reflective of the affected interests. It falls within the range of possible outcomes presented by parties to the proceeding (as shown in the Comparison Exhibit attached hereto as Exhibit A) and is a reasonable and workable solution to the challenges presented in this RTP track of the GRC Phase II proceeding for a Stage 1 Pilot and additional research. The SA is an indivisible package of compromises on key issues that is reasonable in light of the whole record, consistent with the law, and serves the public interest. Accordingly, the Commission should adopt the SA without modification or alteration.[10/]

A. Summary of Settlement Terms

The Settling Parties seek Commission approval of the terms set forth in the attached Settlement Agreement (SA). The key terms of the SA are summarized below: [11/]

8/ D.07-05-060, p. 6.

9/ D.11-05-018, p. 16 (emphasis added).

10/ D.06-06-014, p. 12.

11/ In the event of an inconsistency or a conflict between a term in the SA and a term described in this Motion's "summary" section, Settling Parties intend for the term in the SA to prevail.

1. Eligibility for Stage 1 Pilots

PG&E's bundled customers who are eligible for the B-20, B-6 and E-ELEC rates may participate on those rates in the Stage 1 RTP Pilot, on an opt-in basis. Participation by unbundled customers will depend on whether the decision-making body for any of the Load Serving Entities (LSE, including Community Choice Aggregators (CCA)) affirmatively decide to participate in the Stage 1 Pilots. The Settling Parties hope that at least one of the twelve CCAs currently operating within PG&E's service territory will agree to participate in the Stage 1 Pilots. PG&E agrees to work with its twelve CCAs to seek agreement from one or two of them to participate in the Stage 1 Pilots, if possible. The Settling Parties recognize that CCAs and ESPs may impose other program parameters and/or eligibility requirements for their customers to participate in the Stage 1 Pilots.

2. Rates to be Piloted with an RTP component in Stage 1

No more than three rates shall be included in the Stage 1 Pilots, and that those three rates shall be: Schedules B-20 and B-6 (for the C&I Stage 1 Pilot) and Schedule E-ELEC (for the Residential Stage 1 Pilot).[12/] If, after the initial launch of the Stage 1 Pilots, PG&E determines it has become logistically feasible to implement and include other C&I rate schedules beyond the two included in the C&I Pilot, PG&E may file a Tier 1 Advice Letter (AL) to add any of the following additional C&I rates to Stage 1: B-19, B-19 S, B-19 R, B-20 S, or B-20 R. However, the Settling Parties agree that no other rate schedules may be added to any of the Stage 1 Pilots.

Bundled non-Net Energy Metering (NEM) customers and bundled customers on the following NEM 1.0 or 2.0 tariffs on the three agreed rate schedules shall be included in the Stage 1 pilots: NEMS, NEMEXP-M, NEMEXP, NEM-PS and NEM-MT. Participating bundled NEM customers will have their generation export compensation vary by hour, tracking with the day-ahead hourly RTP generation rates, even if the price is negative (which would result in a generation-related charge, and not a credit).

12/ Settlement Agreement, Section V.B.2.

Because NEM 3.0 will not have been finally decided until after this Agreement is being executed, the Settlement Agreement neither includes nor excludes participation by customers on the NEM 3.0 tariff. If the Commission's final decision on NEM 3.0 is not prescriptive on this question, PG&E will file a Tier 2 AL within 120 days of the Commission's final NEM 3.0 decision, setting forth an eligibility determination regarding NEM 3.0 for the Stage 1 RTP Pilots.

3. Duration of Stage 1 Pilots

The Stage 1 Pilots shall have a duration of 24 months, subject to potential extension after the Commission reviews the Interim Evaluation Report regarding the first 12 months of Stage 1 Pilot operations. That Interim Report will be submitted as part of a Tier 2 Advice Letter 18 months after the targeted launch date of October 1, 2023 for the Stage 1 RTP rates. That Advice Letter will also include a recommendation as to whether the Commission should extend one or more of the Stage 1 RTP Pilot rates, either as is or with minor modifications, beyond the Settling Parties' agreed 24-month period, if shown to be warranted in the Interim Evaluation Report. If the Commission has not timely approved that Advice Letter, the Stage 1 Pilots shall be extended for an additional 90 days to allow PG&E adequate lead-time to complete its notifications to customers of the revised date on which they may be returned to the non-RTP otherwise-applicable underlying tariff.

4. Enrollment

PG&E shall make its best efforts to program and make available for enrollment the three Stage 1 RTP rates by October 1, 2023. In any event, the Settling Parties agree that no Stage 1 Pilot should be launched during the summer season (June 1 to October 1) of any year. Eligible customers may enroll in any of the Stage 1 Pilot rates at any time during the 24-month Stage 1 Pilot duration (i.e., participants do not have to enroll at or before Stage 1 Pilots are launched, but may opt to enroll at any time during the Stage 1 Pilots' 24-month duration. Consistent with Rule 12, Pilot participants who de-enroll from a Stage 1 Pilot RTP rate will not be eligible to re-enroll until at least 12 months have elapsed. The Settling Parties agree that a customer's initial enrollment in a Stage 1 Pilot RTP rate shall not be considered to constitute a "rate change" for purposes of Rule 12, except that residential customers who receive a Smart Panel incentive (described in Appendix A, Attachment C) will be subject to their opt-in rate change being a Rule 12 change if such customer seeks to de-enroll during the first year of their participation in the Stage 1 Residential Pilot operations.[13/]

5. RTP Pricing Dissemination

A Pricing Tool and Communication Platform will be provided as proposed in PG&E's March 29, 2021 testimony, Exhibit PG&E-RTP-1, pp. 5-16 to 5-19. In addition, pricing will be disseminated to the CEC's MIDAS Platform, when it becomes available.

6. Design of Real-Time Rate, including MEC and MGCC

The RTP element of the Stage 1 Pilot RTP rates will replace the generation component of the customer's otherwise applicable rate schedule. The remaining transmission, distribution, Public Purpose Program (PPP) and other charges and taxes remain the same as the otherwise applicable underlying rate.

The generation component to be used in the Stage 1 Pilots' RTP rates will include: (1) a Marginal Energy Charge (MEC), (2) a Marginal Generation Capacity Cost (MGCC), and (3) a Revenue Neutral Adder (RNA) as detailed in the Settlement Agreement. The Settling Parties agree the MGCC component should be cost-based and identical for whatever customer classes receive RTP rate options, Therefore, the MGCC issues subject to the MGCC Study being performed in compliance with D.21-11-017 (in A.20-10-011) should only be decided once by the Commission, to ensure consistency across all MGCC rate elements, including those arising from A.20-10-011 and A.19-11-019.

7. Revenue Neutral Adder (RNA)

The RNA is an additional rate component, on top of the MEC and MGCC components, which is designed to make the forecasted annual generation revenue collected under the three Stage 1 Pilot RTP rates revenue neutral to the base schedule. The Settlement's agreed RNA for

13/ The first year for a Stage 1 Pilot participant is based on their enrollment date, not on the initial launch of the Pilot rates.

PG&E's Stage 1 Pilots' rate design will not only include a component for the non-time-varying Renewable Energy Charge, but will also include TOU adjustments to make each TOU period revenue neutral to the base schedule. However, the RNA adjustment will be specific to each of the three Stage 1 Pilot RTP rate schedules, given that each will correspond to a separate otherwise-applicable rate. Therefore, if, for any of these three RTP rates, that differentiation would cause the peak period to have a lower RNA adder than the off-peak period, a flat RNA will be used for that rate schedule. Agreed illustrative RNA values are presented in Table 1 of the Settlement Agreement. The actual RNA values to be used for the Stage 1 Pilot RTP rates will be updated with revised revenue requirements, marginal costs, load profiles and the final MGCC value (pursuant to all MGCC-related decisions in A.19-11-019) and methodology before implementation.

8. Revenue Requirement Changes Between GRCs

For revenue requirement changes between GRCs, adjustments to the RNA will be made on an equal cents basis to each TOU period to maintain revenue neutrality to the underlying rate. Methodologies for calculating the MEC and MGCC components will not change with revenue requirement changes between GRCs. If PG&E's marginal costs are updated for electric rate design purposes, PG&E will file, by Tier 1 Advice Letter, an update to the Stage 1 Pilots' tariffs that ensure the MGCC, REC, and RNA reflect the new adopted marginal costs. The PCIA will be included in the RNA if the PCIA is still part of the otherwise-applicable generation rate on the underlying schedule.

9. Price Protections

For the two RTP rates to be tested in PG&E's C&I Stage 1 Pilot (B-20 and B-6), there should not be any price protections (such as price caps or bill protection beyond any price cap that may be instituted for the MGCC portion of the rate). However, because residential customers tend to be less sophisticated than C&I customers, for the one residential RTP rate to be tested in the Stage 1 Residential Pilot, the Commission should adopt the protections set forth in the description of the Stage 1 Residential Pilot, presented as Appendix A, Attachment C (i.e., one year of bill protection).

10. Customer Incentives

No participation or technology incentives will be paid to any C&I Stage 1 Pilot participant; however, for the Stage 1 Residential Pilot, limited incentives shall be tested, as described in Appendix A, Attachment C. Specifically, two incentives shall be tested for eligible residential participants, with caps to control total costs. First, up to 1,000 residential participants shall each be eligible for a $300 participation incentive, to be paid out in thirds, as follows: (1) $100 upon enrollment, (2) $100 upon completion of the survey after the first year of operations, and (3) $100 upon completion of the final survey at the end of the 24-month duration of the Stage 1 Pilots. Second, there shall be an additional incentive of $1,625 to help a maximum of 250 residential participants install Smart Panel[14/] technology, to be paid in two installments: approximately 75 percent of the Smart Panel incentives ($1,225) will be paid at the beginning of the Pilot, with the remainder ($400) to be paid upon the participating customer's completion of the first-year survey.

11. Marketing, Education and Outreach

Outreach to potential Stage 1 Pilot participants will include information alerting the participants before they sign-up for either of the Pilots that these Stage 1 Pilots have been designed to operate for a period of 24-months after launch, and that participants may be returned to their OAT at the conclusion of the Pilots, or later if the Commission does not timely act on the Tier 2 Interim Evaluation Report AL which may request authority to extend the Stage 1 Pilot RTP rates beyond 24 months (which, as discussed in Section V.B.3 of the Settlement Agreement is expected to be filed approximately 18 months after the last Stage 1 RTP Pilot was launched).

14/ Smart Panels allow customers choose which loads to be powered at any time and control each individual household circuit.

PG&E's outreach shall focus on customers with energy management systems, energy managers, storage systems, electric vehicle charging, heat pump space heating and/or heat pump water heating, and/or (for C&I customers only) high consumption during peak load periods.

The Settling Parties agree that PG&E will make program-specific marketing content available upon request to third parties and CCAs.

12. Dual Participation

Dual participation is prohibited between Stage 1 Pilot RTP rates and load management approaches or demand response (DR) programs that are dispatched, or otherwise based, on day-ahead price signals or have energy-based payments (including ELRP, CESP, PDP, DRAM, and CBP). Dual Participation is also not allowed between the Stage 1 Pilot RTP rates and programs that are dispatched based on day-of conditions such as the Base Interruptible Program (BIP), or that have day-of options such as ELRP.[15/] As described further below, the Settling Parties agree that the issue of Dual Participation between day-ahead RTP rates and day-of Demand Response programs will be considered in the Interim Evaluation Report. If PG&E determines it is able to mitigate some of the technical difficulties in doing so, PG&E will permit limited dual participation on BIP and/or the day-of option for ELRP and the Stage 1 RTP Pilot to further evaluate impacts, including: 1) isolating *ex-post* and *ex-ante* BIP/ELRP RTP load impacts from dually participating customers so they can be correctly attributed to each program, 2) BIP resource forecasting and counting (i.e., bidding into the CAISO market, RA planning, etc.), 3) double compensation, and 4) generation revenue over- and/or under-collection.

13. Reporting Metrics, Measurement and Evaluation

PG&E shall engage qualified vendors to perform two measurement and evaluation studies that shall be presented as: (1) an Interim Evaluation Report to be completed

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15/ The Emergency Load Reduction Program (ELRP) is a five-year pilot program administered by PG&E that offers participants financial incentives to reduce energy usage during times of high grid stress and emergencies, with the goal of avoiding rotating outages while minimizing costs to customers. The Commission ordered the Investor-Owned Utilities to administer ELRP in Rulemaking (R.) 20-11-003.

approximately 18 months after the Stage 1 Pilots are launched, based on the available data from the first 12 months' operations of the Stage 1 Pilots, and (2) a Final Evaluation Report, based on the full 24 months of Pilot operations (whether extended or not).

In addition to the metrics already recommended in PG&E's testimony (Exh. PG&E-RTP-1, pp. 5-22 to 5-25) and consideration of Dual Participation issues described above, PG&E shall hold a workshop no later than 120 days after the final decision adopting this Settlement, to elicit interested parties' suggestions for further developing, for recommendation to the Commission, metrics for measuring and evaluating Pilot success. The Settling Parties agree that reporting metrics will be determined after the Commission issues its final decision on this Stage 1 Pilots Settlement Agreement, as part of the Pilots' initial design and customer outreach phase as described in Section 13 of the Settlement Agreement.

The Final Evaluation Report shall include a discussion of the potential for self-selection bias, with cautions that the average expected savings per customer that might be expected from broader customer participation in the program would likely be lower than the level measured for the study group, which will inform the decision as to whether any of the Stage 1 Pilots' rates will be continued beyond the Pilots' 24-month period.

Program costs will be reported on a cost-per-participant basis wherever possible. Program cost metrics will be tracked on a fixed as well as a variable basis. The Settling Parties acknowledge that some costs considered "fixed" may actually vary depending on the number of participants and may not be fixed if the program were scaled from a pilot to standard rate option. PG&E agrees to identify those types of costs by the completion of the Final Report.

14. Research Study for Residential, Agricultural and Small Business Customers

PG&E shall conduct an additional Customer Research Study into dynamic pricing rate design and customer preferences for residential, agricultural, and small business customers, as described in PG&E's rebuttal testimony, Exh. PG&E-RTP-2, pp.1-6 to 1-9. PG&E will conduct a workshop within 120 days of the Commission's final decision on this Settlement, to further define the objectives and methods for this research on rate design and preferences. PG&E may conduct further consultations with the Settling Parties regarding this Customer Research Study, if warranted.

15. Net Generator Output Meter (NGOM)

Under PG&E's initial proposal, any Pilot participant with a solar and storage installation would have been required to have a separate NGOM, if their battery storage capacity was less than 10 kW. The purpose of the originally proposed NGOM requirement was to avoid the need to estimate solar production by allowing actual metering to be relied on, instead, for calculating the value of the export and to determine the role of storage in response to RTP price signals.

However, the Settling Parties ultimately agreed that Pilot Participants with energy storage systems between 1 kW and 10 kW, that are not separately metered, instead will be required to agree to work with PG&E to convey hourly charge and discharge data on a monthly or quarterly basis. CALSSA will encourage energy storage companies to use their best efforts to automate transmittal of customer-level hourly charge and discharge data monthly, or more frequently if possible. The Settling Parties agree that interval data is not required for storage less than 1 kW. For participants with battery systems having capacities greater than or equal to 10 kW, the same metering already addressed in the NEM 2.0 tariff shall be used for the Stage 1 RTP Pilots.

16. Cost Recovery of Pilot Costs in Rates

All development, implementation and operating costs for the Stage 1 Pilots, as well as for the separate Customer Research Study for residential, agricultural, and small commercial customers, will be recovered in distribution rates from all customers, allocated by the Equal Percent of Total revenue (EPT) allocation method.[16/] These costs will be tracked in the Dynamic

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16/ PG&E's initial, total cost estimate for its originally proposed Stage 1 Pilot proposal ranged from a low of $7.776 million to a high of $11.096 million (Exh. (PG&E-RTP-1), p. 5-25, Table 5-5). The cost estimate for the Residential, Agricultural and Small Business rate design and preferences study ranged from $400,000 to $700,000 (Exh. PG&E-RTP-1, p. 1-45, lines 15-16). With the Settlement's addition of a Stage 1 Residential Pilot, there will be estimated incremental costs of approximately $1.806 million that were not included in PG&E's initial high-end Stage 1 RTP proposal presented in PG&E-RTP-1, as described in Appendix A, Attachment C, and assume and Real Time RTP Memorandum Account (DRTPMA) for recovery in a future application and testimony. PG&E agrees to separately track four categories of costs within DRTPMA:

a. The costs for the Stage 1 Pilots approved in A.19-11-019 (not including the costs in d. below).

b. The costs for the separate customer research study for residential, agricultural and small commercial customers approved in A.19-11-019.

c. DAHRTP-CEV rate program costs approved in D.21-11-017 (not including the costs in d. below).

d. Joint costs between the Stage 1 Pilots and the DAHRTP-CEV rate program (e.g., joint costs for the Customer Enablement Platform and billing) (not including the costs in a., b., or c., immediately above).

In addition, the amount of bill protection payments for bundled residential customers participating in the residential RTP pilot will also be tracked in the DRTPMA for recovery in a future application and testimony. The cost of these bill protection payments will be related to the generation component on the residential customer's bundled bill. The rate component (e.g., distribution or generation) where these bill protection costs will be recovered, as well as the cost allocation methodology (whether EPT or some other cost allocation methodology), will be determined in the future application.

PG&E will record in the DRTPMA the actual costs it incurs pursuant to the Commission's orders for Dynamic and RTP Pilots and the separate customer research in A.19-11-019 as well as in D.21-11-017 for the DAHRTP-CEV rate program. All recorded costs will be subject to reasonableness review, either through a single application or through a proposal and testimony PG&E will submit in the future for cost recovery. PG&E will record costs in the DRTPMA consistent with how costs have been recorded in its DRTPMA. PG&E can recover the costs recorded to the DRTPMA only after the Commission finds that PG&E has

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1,000 participation incentives of $300, as well as 250 Smart Panel technology incentives of $1,625 each. (*See* Declaration of Anh Dong which is being concurrently filed with the Commission under a separate Motion, and is attached hereto as). However, this $1.806 million estimate of additional incremental costs for the Residential pilot does *not* include any bill protection payments, which cannot be known at this time.

demonstrated in the separate application or testimony that its expenditures were incremental, verifiable, and reasonable, and consistent with the requirements resulting from A.19-11-019 or D.21-11-017, as well as consistent with any other relevant Commission rulings and approvals (including, without limitation, plans and activities submitted by PG&E approved through advice filings discussed elsewhere herein).

17. Generation Over- and Under-Collections (Revenue Requirement Recovery and Avoiding Double Collection)

The Settling Parties acknowledge that tracking generation costs and revenues associated with the RTP rate is extremely complicated and involves several PG&E balancing accounts. Therefore, the Settling Parties agree that the best course of action for the Stage 1 Pilots is to track and study generation costs and generation revenues over the course of the Stage 1 Pilots, with no predefined mitigation or revenue recovery procedures.

PG&E will study over- and under-collection during the Stage 1 Pilots, setting out metrics in the Measurement and Evaluation study. PG&E's study will attempt to differentiate between over- and under-collection structural effects (i.e., due solely to enrollment and disenrollment) and rate-induced changes in customer energy use. PG&E will track each Pilot customer's load profiles, both before and after they began participating in any of the Stage 1 Pilots' RTP rates and compare them to performance under non-RTP-TOU rates as well as the aggregate load of customers not-participating in the Stage 1 Pilots. PG&E will identify those elements of the Energy Resource Recovery Account (ERRA) balancing account that may not be attributable to an RTP rate and will measure possible double counting of annual energy and capacity costs in Stage 1 Pilot customers' rates.

If the study results indicate material and systemic over- or under-collections, PG&E and/or other Settling Parties may file a proposal to modify the RTP rate either during the Stage 1 Pilots, or after their conclusion. The Settling Parties' initial conceptual plans for PG&E's revenue over- and under-collection study are presented in the SA, Appendix A, Attachment B - Background and Conceptual Details of PG&E's Over and Under-Collection study.

18. Information Technology Billing Systems Changes and Timing

PG&E commits to implementing, as soon as practicable, whatever structural changes to PG&E's systems may be necessary to conduct the Stage 1 Pilots agreed upon in this Settlement, including associated external systems for which PG&E is responsible. PG&E advises, and the Settling Parties acknowledge, that to achieve PG&E's goal of timely usability of the systems involved and necessary employee training, any proposed timeline may be modified. The Settling Parties agree that this Settlement shall not preclude any party's right to solicit action from the Commission to address unreasonable delays in implementation of the structural changes to PG&E systems necessary for the Stage 1 Pilots. Prior to contacting the Commission regarding concerns about the timing of PG&E's implementation of the rate changes, the Settling Parties agree to meet and confer with PG&E on the status of the Stage 1 Pilots implementation, discuss options for resolution and allow PG&E a reasonable time to pursue any viable alternative option.

The Settlement Agreement sets forth the target date for PG&E to make best efforts to program and make available for enrollment the agreed upon Stage 1 Pilot RTP rates by October 2023, but if the Commission approves something different from the integrated comprehensive Settlement Agreement's provisions for the Stage 1 Pilots, the launch date for Stage 1 Pilot rate roll-out may take additional time beyond October 2023 and may require a revised budget forecast.

B. The Settlement Agreement is Reasonable in Light of the Record as a Whole

The Settling Parties participated in extensive settlement negotiations for more than one full year, with the goal of developing compromise positions that would permit resolution of the disputed issues in this RTP track of PG&E's 2020 GRC Phase II. The Settlement Agreement is a product of those intensive settlement efforts. The specific outcomes on the issues covered by the Settlement Agreement are within the range of positions and outcomes presented by the parties in the instant proceeding, as discussed below and summarized in Appendix 1 to the SA.

The Settling Parties are pleased that they have been able to reach agreement on all issues in this RTP track of PG&E's GRC Phase II proceeding. As shown in the Comparison Exhibit, many issues were uncontested.

Perhaps the most difficult key contested issue that the Settling Parties were able to successfully resolve were the related issues of: (1) how many rates are feasible and appropriate for inclusion in the Stage 1 Pilots, and (2) which specific rates should be selected for inclusion in Stage 1. The Settling Parties agreed that the three rates to be tested in Stage 1 should be: Schedules B-20 and B-6 (for the Stage 1 C&I Pilot) and Schedule E-ELEC (for the Stage 1 Residential Pilot). For the reasons discussed herein, the selection of these three rates is a reasonable compromise that falls within the range of the parties' positions for any Stage 1 Pilot, as of rebuttal testimony:

PG&E originally proposed an RTP Stage 1 Pilot for two large industrial rate schedules (B-19, customers with 500kW – 1 MW of load; and B-20, customers with loads of 1 MW or higher).[17/] As support for its proposal to focus the Stage 1 Pilot on two key C&I rates and quickly study residential, agricultural and small business PG&E presented a benchmarking study showing that there are 55 RTP rates across the nation, of which all but two involved non-residential rates, and the remainder focused primarily on large commercial and industrial customers who have the control technologies and/or energy managers that enable them to succeed on RTP, Only two programs, both in Illinois, include residential customer eligibility for RTP; neither of those two programs has very many residential customers enrolled, resulting in a lack of information. Thus, PG&E initially proposed that prudence counseled first doing research to inform a successful Stage 2 residential dynamic rate pilot, as well as to recognize that PG&E's billing modernization initiative will limit to three the number of rate schedules that can be included in Stage 1. PG&E originally concluded that large commercial customers not only appear more ready for RTP but have larger loads with greater potential for load shifting during

17/ Exh. (PG&E-RTP-1) pp. 5-6.

the Stage 1 timeframe. PG&E's initial testimony noted that because there was at that time inadequate information to inform the structuring of a successful residential, agricultural or small business RTP pilot as part of Stage 1, much would be learned from PG&E's proposed Customer Research Study, as well as from PG&E's initially-proposed large commercial and industrial Stage 1 Pilot, that could be leveraged to inform a wider Stage 2 RTP pilot or pilots.

Cal Advocates also supported a C&I-focused Stage 1 RTP Pilot, to allow parties to assess potential adverse unintended consequences on a limited scale, with a Customer Research Study on other customer classes to help inform a wider Stage 2 Pilot. Specifically, Cal Advocates' rebuttal testimony expressly opposed proposals by SBUA as well as CALSSA-Enel X to expand the scope of the Stage 1 Pilot beyond large C&I customers. Cal Advocates was concerned expansion at this time might potentially interfere with existing demand response efforts,[18/] and thus opposed CALSSA-Enel X's proposal to allow dual participation with the Base Interruptible Program (BIP) as well as to include a residential RTP option in Stage 1 for the new NEM successor tariff, as well as SBUA's proposed small business pilot. Cal Advocates did not support expansion beyond B-19 and B-20 at this time "because there is little data available to suggest there would be sufficient customer interest to ensure expansion of the pilot to those classes or tariffs would be cost-effective. Instead, Cal Advocates agreed with PG&E that a Customer Research Study is necessary to determine the best approach for designing RTP rates for customers beyond large C&I, at this time. And that PG&E should be required to complete the 24-month Stage 1 C&I Pilot and research study before determining whether it is appropriate to expand the RTP rate to other customer classes.[19/] Finally, Cal Advocates requested that PG&E annually report any double-counting of Stage 1 Pilot customers' generation costs due to Energy Resources Recovery Account true-ups.[20/]

18/ Exh. CalAdvocates-RTP-2, p. 9.

19/ *Id.* at p. 8.

20/ *Id*. at pp. 13-16.

SBUA proposed that, while they agreed the largest PG&E customers may currently be better equipped to respond to an RTP rate than smaller commercial customers, at a minimum the advanced B-1 Storage and B-6 rates should be included in the Stage 1 C&I Pilot (along with B-19 and B-20), because these customers have "demonstrated an interest in alternative rates," and the inclusion of B-6 would provide an option for smaller customers as well as allow testing a non-demand charge rate.[21/]

CALSSA-Enel X proposed that PG&E institute a permanent rate with capped enrollment rather than the Stage 1 C&I Pilot be and extended to Schedule B-1-ST and to residential customers on E-TOU-D, EV2 and E-ELEC.[22/] CALSSA-Enel X expressed believe that any residential customers in PG&E's territory have demonstrated significant interest in enabling technologies and load management offerings and that positive customer experience on RTP could be realized with partnership through third party providers.[23/] Further, CALSSA-Enel X suggested that, if a new rate gets created for residential Net Energy Metering (NEM) customers through Rulemaking (R.) 20-08-020, then that rate should also include an RTP option.[24/]

CLECA's testimony focused on concerns about cost recovery and allocation of RTP Stage 1 Pilot costs. CLECA did not advocate for a specific rate within Stage 1 Pilot.

EPUC and FEA's rebuttal testimony raised similar concerns about cost-shifting and cost-recovery of over- and/or under-collections as raised in CLECA's opening testimony. FEA and EPUC did not advocate a specific rate for inclusion of the Stage 1 Pilot.

21/ Exh. SBUA-RTP-01, p. 8.

22/ Exh. CALSSA-EnelX-RTP-1, p. 5. The B-1-ST rate is available to small business customers with on-site storage; E-TOU-D is an optional TOU rate for residential customers with no baseline quantity allowance and a higher peak to off-peak ratio than the default residential E-TOU-C rate; EV2 is an optional TOU rate available to residential customers with a plug-in electric vehicle, storage and other electrification technologies; and E-ELEC is PG&E's then-proposed (recently adopted) electrification rate for eligible residential customers that PG&E has proposed to become an eligible default rate for Net Billing customers (Net Energy Metering 3.0 customers) in the Comments on the NEM 3.0 Proposed Decision filed January 6, 2022.

23/ Exh. CALSSA-EnelX-RTP-1, p. 4.

24/ Exh. CALSSA-EnelX-RTP-1, p. 5.

In addition to the testimony in this proceeding PG&E and the Settling Parties have, continued to monitor other developments in California involving RTP. The following recent developments caused the Settling Parties to explore and recommend a faster timeline for introduction of a Residential RTP Pilot than PG&E and others had previously envisioned:

1. The CEC is moving forward with Load Management Standard revisions which call for each utility to submit a proposal to their rate-approving body for at least one hourly or sub-hourly marginal cost rate for each customer class within one year of the effective date of the regulations, which are expected to be adopted February 8, 2022 (e.g., March 1, 2023 requirement for RTP rate proposal for the residential customer class).[25/]
2. In parallel with the CEC's Load Management Standard revisions, the Commission draft Distributed Energy Resource (DER) Action Plan 2.0 aims for RTP pilots for all customer classes by 2024.[26/]
3. Certain parties have and are currently advocating for residential RTP pilots in SCE's and SDG&E's GRC Phase 2 cases.
4. The Reliability OIR, R.20-11-003, authorized an RTP pilot for unbundled Valley Clean Energy agricultural irrigation customers, with the hypothesis that RTP could help the grid, despite practically no rate design record on PG&E's distribution delivery rate component.[27/]

25/ Proposed Regulatory Language for the Load Management Standards Regulations (California Code of Regulation Title 20 § 1623(a), within the Load Management Rulemaking (19-OIR-01), December 22, 2021. (Expected to be adopted February 8, 2022.)

26/ Draft California Public Utilities Commission Distributed Energy Resources Action Plan (Draft Commission DER Action Plan 2.0), Aligning Vision and Action (July 23, 2021) p. 8, Vision Element 1A, Action Element 3."By 2024, all utility customer classes have access to multiple rate options, including dynamic and RTP rate pilots that are informed by focus group research and supported by ME&O programs to match various customer preferences and engagement levels. SMJUs and CCAs are encouraged to provide the same for their customers."

27/ D.21-12-015, p. 86.

5. D.21-12-015 authorized the inclusion of residential customers in certain groups for the Emergency Load Reduction Program (ELRP, which is not integrated into the CAISO), to help support the grid when it is stressed.[28/]
6. In D.21-11-017, the Commission did not adopt Enel X's proposal to expand the Business Electric Vehicle Real Time Pricing rate (DAHRTP-CEV) to 500 residential customers. Rather, the Commission noted that RTP is being considered for other customer classes in this proceeding, A.19-11-019.[29/]

During the settlement negotiations in this RTP track of PG&E's 2020 GRC Phase II application, the Settling Parties agreed that a total of no more than three rates would be feasible to pilot in Stage 1, primarily because of billing system programming constraints during PG&E's Billing System Rebuild Project, which will not be complete until at least the end of 2024.

In determining which three rates should be included in the Stage 1 Pilots, in late 2021, the Settling Parties revisited the concept of including a residential RTP demonstration pilot as part of Stage 1.[30/] The Settling Parties exchanged views on what might be able to be learned if a limited residential pilot were conducted as part of Stage 1, as opposed to waiting until after the Stage 1 Pilot and the agreed Customer Research Study (of residential, agricultural, and small commercial customers) can be completed.

The Settling Parties recognized, on balance, that including the E-ELEC residential rate schedule with the limitations and protections described in the Settlement, as part of Stage 1 RTP piloting efforts, is likely to produce valuable initial data regarding residential customer behavior, which, when combined with the additional qualitative research regarding residential RTP, will help more fully inform Commission decision-making regarding: (1) any future development of dynamic price offerings for the residential class, and (2) the cost effectiveness of dynamic price

28/ D.21-12-015, Attachment 2, specifically added group 6 to ELRP for residential customers.

29/ D.21-11-017, p. 29 and p. 34.

30/ The Settling Parties most interested in the 3rd rate and the Residential RTP Pilot are JARP, Cal Advocates and PG&E.

offerings for residential customers. Only thereafter should another, possibly more appropriate dynamic rate design be proposed and adopted in a later rate design proceeding.

In sum, the three rates the Settling Parties agreed to propose in the SA for testing through the Stage 1 RTP Pilots not only fall within the range of parties' positions as of rebuttal testimony, but also reflect other, more recent developments. Specifically, the Settling Parties' carefully balanced compromise accommodates SBUA's desire to include B-6 to allow small commercial customers the opportunity to opt-into RTP, while recognizing that there can be only three rates in the Stage 1 Pilot because of billing system constraints. AECA's concerns were addressed by ensuring that Agricultural customers' RTP preferences and capacity is carefully studied first so that a tailored proposal that works for Agricultural customers can be tested later, such as in any potential Stage 2 Pilot (or Pilots). CalSSA-ENEL X's desire for a Stage 1 Residential Pilot was addressed by adding a third rate (E-ELEC) – above and beyond the B-20 and B-6 rates to be tested in the agreed Stage 1 C&I Pilot. The agreed, limited Stage 1 Residential Pilot will be subject to certain protections as well as limited customer incentives to control costs.

Cal Advocates had expressed concerns about expanding the Stage 1 Pilot beyond B-19 and B-20, including that there is not yet adequate data to find that doing so would be cost-effective, and that residential customers should be allowed enough time after the ongoing roll-out of the default TOU rate transition to get used to TOU before they are approached about an RTP Pilot. The SA addresses this concern by selecting the new E-ELEC rate for the Stage 1 Residential Pilot, because, not only is it a new rate that is expressly focused on customers who have adopted technologies like storage that are critical for success on an RTP rate, but it is already expected to be the best rate for such customers.

Another contested issue that the parties were able to settle was dual participation. PG&E proposed to prohibit all dual participation, while CalSSA-Enel X proposed to allow dual participation between the Stage 1 RTP Pilot and both the Base Interruptible Program (BIP) and Emergency Load Reduction Pilot (ELRP). The Settling Parties discussed technical challenges and policy issues associated with implementing such dual participation, particularly without: (a) the experience from administering an RTP rate, (b) load impacts from pilot participants in PG&E's service territory, and (c) the ability to ensure compliance with CPUC dual participation rules. The Settling Parties agreed that PG&E would use the Interim Evaluation Report to discuss which of the challenges it believes can be sufficiently mitigated to allow potential testing of limited dual participation between an RTP Pilot and/or the day-of option for ELRP, which, if possible, could be used to inform a determination of whether dual participation beyond the Stage 1 Pilots.

The concerns of Cal Advocates, CLECA, EPUC and FEA concerns about cost-shifting are addressed through the Settlement Agreement's various provisions requiring tracking, studying and dealing with any resulting revenue over- and/or under-collections, as well as potential double recovery.

As regards RTP rate design, the SA's recommendations are also reasonable in light of the record as a whole. All the Settling Parties fully support day-ahead hourly pricing, which provides better opportunities for customers to plan around rate values compared to day-of pricing, as well as the overall three-part RTP rate design (consisting of Marginal Energy Costs (MEC), Marginal Generation Capacity Costs (MGCC), and a Revenue Neutral Adder (RNA)) in testimony. The SA supports the use and efficient consideration of the MGCC Research Study described in Exhibit PG&E-20 and adopted in the DAHRTP-CEV proceeding. The SA's RNA design is now revenue-neutral to the otherwise applicable tariff (OAT) in each time-of-use (TOU) period.[31/] This allows for small RNA changes between TOU periods and schedules, thus providing a greater incentive for load shifting.

Finally, the Settling Parties have agreed to allocate program costs from the Stage 1 Pilots to all customers in Distribution using the Equal Percent of Total revenue (EPT) method, which is a compromise between the Purpose Programs (PPP) by equal cents proposal by Cal Advocates

31/ Unless this causes a smaller RNA value in the peak period compared to off-peak.

and PG&E's position of using standard distribution allocation (supported by CLECA and EPUC). This balanced outcome recognizes that, while this spending is functionally distribution, its purpose is broader as it is hoped RTP could ultimately benefit both the generation system as well as the delivery system, by incenting customers to manage their loads.

All the provisions agreed to in the SA, including both the C&I and Residential Stage 1 Pilots, plus the parallel Customer Research Study, will contribute to important learnings on RTP from Stage 1 that can help inform a successful, wider Stage 2 RTP Pilot (or pilots). Response to RTP price signals could potentially help California make better usage of clean intermittent renewable energy sources that tend to predominate in the hours during which generation is typically lower cost. However, whether such potential can be realized needs to be tested and researched, including through the Settlement's proposed Stage 1 Pilots and Customer Research Study.

The Settling Parties recognize that the Commission may have additional questions about the Settlement Agreement. The Settling Parties will provide a Settlement Panel to appear if desired during evidentiary hearings to answer questions in a manner that does not violate the Commission's confidentiality requirements under Rule 12. In addition, or as an alternative, the Commission could also consider issuing a list of written questions to which the Settling Parties could jointly respond in writing, given enough time to do so as a group. Such joint written responses could perhaps be received as a late-filed exhibit, if necessary, as was done to receive joint responses to the Commission's questions about the Revenue Allocation Settlement submitted in April 2021 in a prior track of this GRC Phase 2 proceeding. In any event, the Settling Parties are committed to responding in whatever ways are most appropriate and efficient to provide the Commission with answers to whatever questions it may want to be addressed if further support is desired to inform its assessment of whether this Settlement is reasonable in light of the record, consistent with law, and in the public interest.

C. The Settlement Agreement is Consistent with Law

The Settling Parties believe that the Settlement Agreement is fully consistent with relevant statutes, Commission decisions, and public policy, including the Rate Design Principles adopted by the Commission in D.15-07-001. In particular, implementing the SA terms will ensure the RTP pilot residential rates are aligned with the Commission's cost-of-service,[32/] affordability,[33/] and customer acceptance.[34/]

D. The Settlement Agreement is in the Public Interest

The Commission has determined that the "public interest" criterion is satisfied by a settlement that "commands broad support among participants fairly reflective of the affected interests" and "does not contain terms which contravene statutory provisions or prior Commission decisions."[35/] Here, all of the active parties on RTP issues in Phase 2 of this proceeding have either joined this Motion (and signed the attached Settlement Agreement indicating that they believe the Settlement Agreement represents a reasonable compromise of their respective positions) or affirmatively indicated that they do not oppose it. The Settling Parties are knowledgeable and experienced regarding the issues in this proceeding and, in agreeing to the Settlement Agreement, have applied their collective experience to produce appropriate, well-conceived recommendations. The Settling Parties have vigorously negotiated and succeeded in achieving a settlement that they believe balances the various interests affected in the RTP track of this GRC Phase 2 proceeding. In addition, as noted above, the Settling Parties do not believe that the SA contains terms that would contravene statutory provisions or prior Commission decisions. Finally, the SA includes provisions for identifying potential under-collection and cross-subsidization concerns while allowing a limited Stage 1 Pilot to proceed to gather key early learnings and hopefully deliver some initial GHG reduction benefits and

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32/ See D.15-07-001, p. 264 (RDPs #2, #3, #7, #8, #9).

33/ See *Id.* (RDP #1).

34/ See *Id.* (RDP #6).

35/ D.10-06-015, p. 11.

generation cost savings as well – all of which are in the public interest. The limitations on the residential Stage 1 RTP Pilot result in a reasonable initial test on appropriate residential customers for now, while minimizing the incremental additional costs it adds to Stage 1.

The rate design for the three RTP Pilot test rates all focus on Marginal Generation Costs, which are composed of MEC and MGCC. While including an MEC component in RTP rates is fairly straightforward (in that it reflects the marginal cost to load of procuring energy in the day-ahead timeframe, i.e., the CAISO day-ahead market), including the MGCC component is more complex. MGCC recovers expected costs related to purchasing system capacity, which D. 21-11-016 (at p. 49) determined should be calculated from the net cost of new-build standalone four-hour batteries, as adopted in Phase I of this proceeding. The Settlement Agreement's approach will send a capacity price signal during the hours in which the grid is most stressed, in an effort to incent customers to reduce load in those hours, which could, eventually (once load-shifting has been verified), yield reductions in the need to acquire as much battery storage generation capacity.[36/] Thus, if the RTP rates tested in Stage 1 are successful, the longer-term goal should be to reduce rates for *all* customers (whether they participated on an RTP rate or not). In the shorter term, the RTP rate design's capacity price signal will help the grid to the extent that load is shifted out of those hours. The MGCC Research Study will provide information on the appropriate methodology to calculate a capacity cost that accurately signals grid stress in the day-ahead timeframe and is thus of critical importance.

For all of these reasons, the public interest criterion is satisfied. As stated above, if the Commission has additional questions, the Settling Parties would gladly either appear as a panel during hearings and/or jointly provide written answers to any questions the Commission might propound.

36/ The MEC may also be high during hours with high grid stress; however, MGCC represents the marginal cost *in addition to MEC* that is associated with maintaining sufficient system capacity. See A.19-11-019, p. 42.

1. The Settlement Agreement is Reasonable and Should be Adopted without Modification

The Settling Parties view the proposed SA as an integrated and cohesive resolution of all of the issues in this track of the GRC Phase 2 proceeding. The various provisions of the Settlement Agreement reflect specific compromises among a wide range of litigation positions presented by parties with differing interests that are fairly representative of those affected. Although each provision of the SA is discussed separately in the summary above, the SA is presented as a whole, and each provision of the Agreement is dependent on the other provisions; in some instances, the proposed outcome reflects a party's concession on one issue in consideration for the outcome provided on a different issue.

Modification of any one part of this integrated Settlement Agreement would harm the carefully balanced compromises achieved among the Settling Parties, who represent a wide range of interests. Indeed, the SA expressly provides that adoption of only a portion of the Settlement Agreement would free the Settling Parties from their settlement obligations.[37/] Accordingly, in keeping with long-standing Commission precedent in favor of consideration of "whether the settlement ***as a whole*** produces a just and reasonable outcome,"[38/] the Commission should consider and approve this SA as a whole, without any alteration or modification.

IV. THE SETTLING PARTIES HAVE COMPLIED WITH THE REQUIREMENTS OF RULE 12.1(B)

Settlement discussions in the 2020 GRC Phase II proceeding began long ago, pursuant to a notice of settlement conference provided by PG&E to the service list under Rule 12.1(b), on November 24, 2020. Settlement discussions regarding RTP issues initially arose before RTP issues were bifurcated onto a later track. Even after settlements on all other GRC Phase II issues had been filed and were later approved, all of the active parties to this proceeding engaged in exploring a potential RTP Settlement continued their intensive good faith negotiations. Discussions during over 30 weekly settlement meetings on RTP issues, as well as related ad hoc

37/ Settlement Agreement, Section III.

38/ D.11-05-018, p. 16 (emphasis added).

subgroup meetings and other communications among the parties, resulted in agreement on the terms and conditions in the SA. Out of an abundance of caution, on January 6, 2022, PG&E filed and served on all parties to A.19-11-019 a Notice of Settlement Conference pursuant to Rule 12.1(b), which was held January 12, 2022 from 3 p.m. to 4:30 p.m.[39/] And on January 11, 2022, PG&E sent out emails attaching the proposed Settlement to various parties to its GRC Phase 2 proceeding who were believed potentially interested in reviewing it to either decide to sign or indicate that they do not oppose.

V. REQUESTED FINDINGS

Based on this Joint Motion, the SA attached hereto, and the record in this proceeding, the Settling Parties respectfully request that the Commission make the following findings:

- The Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest.
- The Settlement Agreement should be adopted in its entirety with no modifications.
- The Commission should grant the Settling Parties' request that the description of the Residential Pilot, presented as Appendix A, Attachment C, should be received into evidence by stipulation (or jointly sponsored by a Settlement Panel, if deemed necessary), and find its terms to be reasonable, including that it provides all residential RTP Pilot customers with one year of bill protection as well as provides at most 1,000 participating residential customers a participation incentive, paid out over the full 24-month pilot period, and provides at most 250 participants technology incentive payments for Smart Panels. On the other hand, the Commission should find it reasonable not to include such protections for C&I customers, who tend to be more sophisticated than residential customers and may have energy managers on staff with access to the automated technologies and/or risk hedging strategies needed to succeed on RTP.
- Finally, the CPUC should receive into evidence in this proceeding the Declaration of PG&E's Anh Dong, being concurrently filed under a separate Motion and a copy of which is attached hereto as Appendix B Attachment C. To support the Settlement, Ms. Dong's Declaration presents the incremental costs of adding a limited residential RTP Pilot as part of Stage 1; all Settling Parties reviewed this Declaration before they signed the Settlement.

39/ The Settling Parties stipulated that the timing of this Notice should be shortened to six days.

VI. CONCLUSION

As demonstrated herein, the SA is reasonable in light of the entire record, is consistent with law, and promotes the public interest. Accordingly, the Settling Parties respectfully request that the Commission expeditiously approve the Settlement Agreement without modification and make the findings set forth in Section VI of this motion.

All of the RTP Settling Parties have reviewed and authorized PG&E to file, on their behalf, this Joint Motion and Settlement Agreement on behalf of all of the RTP Settling Parties per Rule 1.8 of the Commission's Rules of Practice and Procedure.

Respectfully, this 14th day of January, 2022.

Respectfully submitted,

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Dated: January 14, 2022

APPENDIX A

Settlement Agreement, including
Attachment A - Comparison Exhibit

SETTLEMENT AGREEMENT IN PG&E'S 2020 GENERAL RATE CASE PHASE II (APPLICATION A.19-11-019) ON REAL TIME PRICING ISSUES INCLUDING STAGE 1 PILOTS

I. INTRODUCTION

In accordance with Article 12 of the Rule of Practice and Procedure of the California Public Utilities Commission (Commission), the parties to this Real Time Pricing (RTP) Settlement Agreement (Settlement Agreement) listed below in Section II (Settling Parties), agree on a mutually acceptable outcome to all of the program design issues for the RTP Pilot programs (Stage 1 RTP Pilots) for commercial and industrial (C&I) and residential customers, as presented in Application (A.) 19-11-019, Application of Pacific Gas and Electric Company (PG&E) to Revise Its Electric Marginal Costs, Revenue Allocation and Rate Design (GRC Phase II). The Settling Parties further agree that PG&E should also conduct a separate research study for residential, agricultural and small business customers (Customer Research Study).[1] The Settling Parties represent that this Settlement Agreement resolves all RTP-related within the scope of this GRC Phase II proceeding.[2/] The details of this Settlement Agreement are set forth herein.

The testimony served by the parties active in this track of PG&E's 2020 GRC Phase II advanced differing views on certain aspects of the scoped Stage 1 RTP Pilot issues, including on pilot design. In compliance with Rule 12.1(a) of the Commission's Rules of Practice and Procedure, the parties' positions in testimony are shown in the Comparison Exhibit attached hereto as Appendix A, Attachment A. The active parties have debated their positions at length

1/ The Customer Research Study will evaluate dynamic pricing rate design and customer preferences and is discussed below in Section B.14.

2/ As described in PG&E's Opening and Rebuttal Testimony, future pilots (e.g., Stage 2 Pilots) can be informed by the results of the Stage 1 RTP Pilots, as well as by the Commercial Electric Vehicle Real Time Pricing Pilot (DAHRTP-CEV Pilot) adopted in A.20-10-011, other utilities' RTP pilots being developed in their GRC Phase II proceedings, and the Customer Research Study proposed in this proceeding. Customer Research Study issues are discussed below in Section V.B.14.

through over 30 in-depth settlement conferences held over the past twelve months,[3/] and have bargained earnestly and in good faith to reach a reasonable compromise concerning the RTP issues pending in this proceeding including two Stage 1 RTP Pilots (one for C&I customers and one for residential customers) that PG&E plans to launch in October 2023. This Settlement Agreement is the product of their detailed, arms-length negotiations on various disputed issues. These negotiations considered the interests of all active parties on Stage 1 RTP Pilot program design and Customer Research Study issues for consideration in this proceeding. The resulting Settlement Agreement addresses and resolves each of these issues in a fair and balanced manner.

The Settling Parties reached this Settlement Agreement by mutually accepting concessions and trade-offs among themselves. Thus, the various elements and sections of this Settlement Agreement are closely interrelated and should not be altered, as the Settling Parties intend that the Settlement Agreement be treated as a package solution that strives to carefully balance and align the interests of each party. Accordingly, the Settling Parties respectfully request that the Commission approve each, and every, aspect of this Settlement Agreement without modification. Any material change to the Settlement Agreement shall render it null and void, unless all Settling Parties agree in writing to such changes.

II. SETTLING PARTIES

The Settling Parties are as follows:

- Agricultural Energy Consumers Association (AECA)
- California Large Energy Consumers Association (CLECA)
- California Solar and Storage Association (CALSSA)
- Enel X North America, Inc. (ENELpX)
- Energy Producers and Users Coalition (EPUC)

3/ The extended settlement process has been necessary because the design of the Stage 1 RTP Pilots raised novel technical and implementation issues. Resolution of many of these issues in this settlement process depended on the efforts of the active parties to conduct and present investigations to each other.

- Federal Executive Agencies (FEA)
- OhmConnect, Inc.
- PG&E
- Public Advocates Office at the California Public Utilities Commission (Cal Advocates)
- Small Business Utility Advocates (SBUA)

The following Parties in A.19-11-019 who are not signatories to the final Settlement Agreement, but do not oppose it.[4/]

- Center for Accessible Technology (CforAT)
- California Manufacturers and Technology Association (CMTA)
- Direct Access Customer Coalition (DACC)
- Energy Users Forum (EUF)
- Joint Community Choice Aggregators (JCCAs)
- The Utility Reform Network (TURN)

III. RTP SETTLEMENT CONDITIONS

This Settlement Agreement resolves the issues raised by the Settling Parties in A.19-11-019 on Stage 1 RTP Pilots, including a pilot for C&I customers (C&I Stage 1 RTP Pilot) and a pilot for residential customers (Residential Stage 1 RTP Pilot), and a Customer Research Study for residential, agricultural and small business customers, subject to the conditions set forth below:

1. This RTP Settlement Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described herein, and it supersedes prior oral or written agreements, principles, negotiations, statements,

4/ The following parties of A.19-11-019 did not file testimony on any of the issues addressed in this Settlement Agreement and did not participate in settlement discussions: California Farm Bureau Federation (CFBF), Natural Resources Defense Council (NRDC), Sierra Club and Solar Energy Industries Association (SEIA).

representations, or understandings among the Settling Parties with respect to those matters.

2. This Settlement Agreement represents a negotiated compromise among the Settling Parties' respective litigation positions on the matters described; the Settling Parties have assented to the terms of this Settlement Agreement only to arrive at the terms embodied herein. Nothing contained in this Settlement Agreement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the Settling Parties on these matters in this proceeding.
3. This Settlement Agreement does not constitute and should not be used as a precedent regarding any principle or issue litigated in this proceeding or in any future proceeding.
4. The Settling Parties agree that this Settlement Agreement is reasonable, in light of the testimony submitted, consistent with law, and in the public interest.
5. The Settling Parties agree that the language in all provisions of this Settlement Agreement shall be construed according to its fair meaning and not for or against any Settling Party based on whether that Settling Party or its counsel or advocate drafted the provision.
6. The Settling Parties agree that the Settlement Agreement addresses all issues regarding the 2020 GRC Phase II RTP proposals pending in this track of the GRC Phase II proceeding, including: design of the C&I Stage 1 RTP Pilot and the Residential Stage 1 RTP Pilot, and a separate Customer Research Study for residential, agricultural and small business customers.
7. This RTP Settlement Agreement may be amended or changed only by a written agreement signed by all the Settling Parties.
8. The Settling Parties shall jointly request Commission approval of this Settlement Agreement and shall actively support its prompt approval. Active support shall

include written and oral testimony if testimony is required, briefing if briefing is required, comments and reply comments on the proposed decision, advocacy to the Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

9. The Setting Parties intend that the terms of this Settlement Agreement are to be interpreted and treated as a unified, integrated agreement to the degree applicable to RTP and the Stage 1 RTP Pilots. In the event the Commission rejects or modifies any portion of this Settlement Agreement, the Settling Parties reserve their rights under Commission Rules 12.4 and 12.6.

IV. PROCEDURAL AND SETTLEMENT HISTORY

The procedural history of PG&E's 2020 GRC Phase II proceeding, from the date the application was filed through November 2021, appears in Section 1 (pages 2-6) of the Commission's recent decision on the issues scoped for the main track of PG&E's 2020 GRC Phase II, Decision (D.) 21-11-016, and is incorporated herein by reference.

The following summarizes the additional procedural history for the RTP track in A.19-11-019, to which this Settlement relates. On August 27, 2020, the assigned Administrative Law Judge (ALJ) issued a ruling clarifying the procedural schedule and inviting parties to provide testimony on RTP rate design issues for consideration in this proceeding. That Ruling specified the following deadlines for submittal of any such testimony: Cal Advocates by October 23, 2020; other intervenors by November 30, 2020; and rebuttal testimony from all parties by February 15, 2021. Cal Advocates timely served its RTP testimony on October 23, 2020 followed by RTP testimony served on November 30, 2020 from three other intervenors: AECA, SBUA, CALSSA, and OhmConnect.[5/]

5/ CALSSA and OhmConnect initially served joint testimony on November 30, 2020 under the name "Joint Advanced Rate Parties (JARP)." That testimony was superseded by the Responsive Testimony and Rebuttal Testimony served by CALSSA and Enel X on May 28, 2021, and July 30, 2021, respectively.

In November and December 2020, two motions were filed seeking to consolidate the RTP rate design issues with a separate Commission proceeding considering RTP structure for certain PG&E electric vehicle charging station operators (A.20-10-011). Both motions were denied. However, several parties jointly filed a motion on January 27, 2021, seeking to bifurcate RTP rate design issues from the other marginal cost, revenue allocation and rate design issues in this proceeding and consider them on a delayed track that would allow for complementary consideration of issues arising in A.20-10-011. That motion was granted on February 2, 2021. The bifurcation of the RTP issues required a revision to the procedural schedule, and an Assigned Commissioner's Amended Scoping Memo and Ruling was filed on February 16, 2021, including the following new dates for submitting testimony on RTP issues: March 29, 2021 for PG&E's opening testimony, May 28, 2021, for intervenors' responsive testimony, and July 30, 2021 for parties' rebuttal testimony. Accordingly, PG&E, Cal Advocates, CALSSA and Enel X (jointly), SBUA, FEA, CLECA, and EPUC duly served testimony on those dates.

Ongoing weekly settlement meetings began January 15, 2021. As of mid-January 2022, over 30 weekly settlement meetings had been held. Additional meetings were held to address ad hoc topics delegated to subgroups with results reported back to all participants during the weekly meetings.[6/] As outlined above, a total of fourteen (14) parties participated in at least one of the weekly settlement meetings and a core group of nine (9) parties continued active attendance and involvement in the weekly settlement and ad hoc meetings throughout the year. Out of an abundance of caution, per Rule 12.1(b) of the Commission's Rules of Practice and Procedure, on January 6, 2022, after active parties stipulated to a reduced noticing time, PG&E provided a six-day notice of a January 12, 2022 settlement conference about this Settlement Agreement before it was finalized and executed, to be filed and served under a Motion for Approval of Settlement.

6/ Ad hoc topics included marginal generation capacity cost (MGCC) and revenue neutral adder (RNA) rate design, and a potential third rate.

In a Second Amended Scoping Memo and Ruling dated August 25, 2021, the Assigned Commissioner set hearings on RTP issues for January 24 to 26, 2022. On July 30, 2021, PG&E sent a notice for a meet-and-confer conference scheduled for August 9, 2021, which the ALJ subsequently allowed PG&E to delay. PG&E re-noticed the meet-and-confer conference to November 17, 2021, when it was duly held.

On December 22, 2021, Assigned ALJ Sisto issued an Email Ruling confirming the January 24 to 26, 2022 hearings, to begin at 9:30 am each day, and setting a schedule for prehearing preparations, including a January 18, 2022 "dry run" to allow testing of all participants' equipment and connectivity as these hearings must be held remotely to support the health and safety of all participants given the continuing COVID-19 pandemic including the recent surge caused by the Omicron variant.

V. SETTLEMENT TERMS

A. General Terms

Considering and both recognizing and compromising the litigation positions taken by the individual parties, the Settling Parties agree to Stage 1 RTP Pilots with design features set forth in this Settlement Agreement, along with a plan to conduct a separate Customer Research Study for residential, agricultural, and small business customers. The Settling Parties agree that the primary objectives of the Stage 1 RTP Pilots are to: (1) develop an RTP rate design that can change each hour while collecting the allocated revenue requirement, and (2) test the hourly RTP rate design in the Stage 1 RTP Pilots for three opt-in PG&E rates (B-6, B-20 and E-ELEC), to assess customer interest in and barriers to participating on such a rate, and (3) accurately measure the degree of load reduction and load shifting and the associated impacts on greenhouse gas emissions achieved by customers on these Stage 1 RTP Pilot rates. The Stage 1 RTP Pilot design proposals presented in this Settlement Agreement are reasonable in light of the entire record in this proceeding, consistent with law, and reflect a fair and balanced compromise of the Settling Parties' proposals relating to the issues included in this Settlement Agreement that is in the public interest.

The Settling Parties agree that all testimony served prior to the date of this Settlement Agreement, which each Party asks to be accepted into evidence, addressing the issues resolved by this Settlement Agreement should be admitted into evidence without cross-examination by the Settling Parties. Because this Settlement Agreement includes a Residential Stage 1 RTP Pilot using the E-ELEC rate which was not addressed in PG&E's testimony prior to the date of this Settlement Agreement, PG&E is preparing a Declaration of Witness Anh Dong setting forth the related costs that would be incremental to the costs set forth in PG&E's prior testimony. These estimated Residential Stage 1 RTP Pilot costs that are incremental to the cost estimates presented in PG&E's opening testimony on March 29, 2021 are summarized below in Section V.B.16. and detailed in Appendix A, Attachment C, and in the Declaration of Anh Dong in Support of PG&E on Residential Stage 1 Pilot Cost Estimates, presented in Appendix B, Attachment C

The Settling Parties agree that, subject to the confidentiality restrictions under Rule 12.6, they shall make witnesses available to answer any questions the Commission may have about this Settlement Agreement, either: (1) as part of a Settlement Panel to appear at a mutually agreeable time during the scheduled remote evidentiary hearings, if the Commission so desires, and/or (2) by jointly preparing written responses to written questions from the Commission, for submission into the record at hearings or as a late-filed exhibit if it cannot be finalized before the close of evidentiary hearings on January 26, 2022.

As described below in Section V.B., the Settling Parties agree to the elements and parameters of the C&I and Residential Stage 1 RTP Pilots, and a separate Customer Research Study for residential, agricultural, and small business customers.

B. Uncontested and Settled Issues

1. Eligibility

The Settling Parties agree that PG&E's Bundled service customers eligible for the rates approved for inclusion in the Stage 1 RTP Pilots (B-6, B-20 and E-ELEC)[7/] shall be eligible to participate in the Stage 1 RTP Pilots, except for Net Energy Metering 3.0 (NEM 3.0)[8/] customers discussed below in Section V.B.15. The Settling Parties agree that participation in each rate approved for inclusion in the Stage 1 RTP Pilots will be solely at the eligible customers' option.

Participation by Unbundled service customers will depend on whether the decision-making body for their Load Serving Entity (LSE) (e.g., Community Choice Aggregator (CCA) or Direct Access (DA) Energy Service Provider (ESP)) has decided to participate in the Stage 1 RTP Pilots.[9/] The Settling Parties hope that at least one of the twelve CCAs within PG&E's

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7/ See Section V.B.2. below for clarification on the rate schedules to be included in the Stage 1 RTP Pilots.

8/ Also referred to as "Net Energy Metering 2.0 Successor Tariff customers", or "Net Billing customers."

9/ Bundled customers receive their generation from PG&E. Unbundled service customers receive their generation from another non-PG&E LSE, defined as an ESP, which includes CCAs and DA providers.

service territory will agree to participate in the Stage 1 RTP Pilots. Accordingly, the Settling Parties agree that PG&E shall work with the twelve CCAs within its service territory to seek agreement from one or two CCAs to participate in the Stage RTP 1 Pilots, if possible. While a specific deadline for CCA commitment to participate in the Stage 1 RTP Pilots cannot be stated at this time, PG&E will alert interested CCAs when their formal commitment would be needed to enable them to join.

2. Stage 1 RTP Pilot Rate Schedules

The Settling Parties agree that three (3) is the maximum number of rate schedules to be included in the Stage 1 RTP Pilots.

a. The Settling Parties agree to pilot a day-ahead hourly real time pricing (DAHRTP) generation component based on the California Independent System Operator (CAISO) hourly Day-Ahead Market (DAM) for eligible customers as follows:

i. Three electric rate schedules shall be included in PG&E's Stage 1 RTP Pilots: Schedule B-6 and Schedule B-20[10/] in the C&I Stage 1 RTP Pilot, and Schedule E-ELEC in the Residential Stage 1 RTP Pilot (eligible rate schedules). As detailed below in Section 10.B.i., participation incentives will be provided only to the first 1,000 E-ELEC customers who enroll in the Residential Stage 1 RTP Pilot, but any customer eligible for E-ELEC will be eligible to enroll in the Pilot, even if the 1,000 customer cap on participation incentives has been reached.

ii. After the initial launch of the Stage 1 RTP Pilots, if PG&E determines that it has become logistically feasible to implement and include other rate schedules, PG&E may file a Tier 1 Advice Letter (Tier 1 Supplemental Rates AL) to add to the C&I Stage 1 RTP Pilot eligible rate schedules any of the

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10/ No Option R for Solar or Option S for Storage versions of the B-20 rate schedule will be included in the C&I Stage 1 RTP Pilot. See the B-20 tariff for more details on Option R for Solar and Option S for Storage.

following C&I rate schedules: B-19, B-19S, B-19R, B-20S, or B-20R. However, the Settling Parties agree that there shall not be any other rate schedules added to any Stage 1 RTP Pilot.

b. The Settling Parties agree to the following eligibility terms for NEM and non-NEM Bundled service customers served by PG&E on the eligible rate schedules:

i. non-NEM Bundled service customers on the eligible rate schedules shall be eligible for the Stage 1 RTP Pilots.

ii. NEM Bundled service customers on the eligible rate schedules:

- who are on the following NEM 1.0 or 2.0 tariffs shall be eligible for the Stage 1 RTP Pilots: NEMS, NEMEXP-M, NEMEXP, NEM-PS and NEM-MT.
- who are on VNEM and NEMA shall not be eligible for the Stage 1 RTP Pilots.
- will have their generation export compensation vary by hour, tracking with the hourly RTP generation rates, even if the price is negative (which would result in a generation-related charge and not a credit).

c. The Settling Parties agree to the following eligibility terms for Unbundled service customers served by CCAs, or ESPs (i.e., DA providers), on the eligible rate schedules:

i. Non-NEM and NEM 1.0 & 2.0 Unbundled service customers who opt into any of the eligible rate schedules can participate in the Stage 1 RTP Pilots if their CCA or ESP elects to participate and offers RTP for its generation energy rate component.

ii. The Settling Parties recognize that CCAs and ESPs may impose other eligibility requirements for their customers to participate in the Stage 1 RTP Pilots.

d. Because the NEM 3.0 tariff has not yet been established, this agreement does not include or exclude participation in the RTP pilot by customers on the NEM 3.0 tariff. If the Commission's final NEM 3.0 decision is not prescriptive on this question, PG&E will file a Tier

2 AL (Tier 2 Net Metering Eligibility AL) within 120 days of the NEM 3.0 decision with an eligibility determination.

3. Duration

a. The Settling Parties agree that the duration of the Stage 1 RTP Pilots shall be 24 months after the launch date for the Stage 1 RTP Pilot rates. As summarized below and further detailed below in Section V.B.13., the Settling Parties agree that two measurement and evaluation studies (discussed further below) shall be conducted, covering both the C&I and Residential Stage 1 RTP Pilots: (1) an Interim Evaluation to be conducted after 12 months of data has been collected for both Stage 1 RTP Pilots; and (2) a Final Evaluation to be conducted after 24 months of data is available from the operations of each of the Stage 1 RTP Pilots. As summarized below and further detailed below in Section V.B.13., based on the Interim Evaluation, a recommendation may be made to extend the Stage 1 RTP Pilot rates, as is or with minor modifications, beyond the Pilots' 24-month period, if shown to be warranted by the Interim Evaluation. See Appendix A, Attachment E for a timeline of Stage 1 RTP Pilot Measurement and Evaluation Studies, and Pilot Duration and Ending.

(1) <u>Summary of Interim Evaluation Report and AL</u>: As detailed below in Section V.B.13., the Settling Parties agree that PG&E shall file a Tier 2 AL (Tier 2 Interim Evaluation Report AL) expected to be approximately 18 months after all three of the RTP rates approved for the Stage 1 RTP Pilots have been launched. This AL will include a recommendation as to whether any of the rates included in the Stage 1 RTP Pilots should remain available beyond the Pilots' 24-month period. The AL shall request Commission action within 90 days, if possible. However, if the Commission has not acted on that AL within 120 days, the Settling Parties agree that PG&E will notify the Commission and all Parties that the Pilot Rates will be extended at least an additional 90 days beyond the Pilots' 24-month period (which is at the least 8 months after the Interim Evaluation Report AL will be filed), to allow PG&E adequate lead-time to

complete its notifications to customers of the revised date on which they may be returned to the non-RTP version of their Otherwise Applicable Tariff (OAT).

(2) Summary of Final Evaluation Report and AL: As detailed below in Section V.B.13., if the Commission decides to continue any of the Pilot rates beyond the Pilots' 24-month period in response to the Interim Evaluation Report AL, as described above, the Settling Parties also agree that the Final Evaluation Report AL will include a recommendation on whether one or more of the RTP rates being tested should be continued on a broader scale. Stage 1 RTP Pilot participants will not be moved back to their OAT unless the Commission determines this outcome in response to the Final Evaluation Report AL. Stage 1 RTP Pilot participants can return to their OAT at any time if they so choose.

4. Enrollment

a. Enrollment by customers in the Residential and C&I Stage 1 RTP Pilots shall be subject to the terms described above in Sections V.B.1. and V.B.2.

b. Participation incentives to be provided only for Residential Stage 1 RTP Pilot participants (not for C&I Stage 1 RTP Pilot participants) are described below in Section V.B.10.

c. The Settling Parties agree that all aspects the Stage 1 RTP Pilot rates are optional rates and are subject to Electric Rule 12 (Rule 12). Settling Parties agree that, consistent with Rule 12, any Pilot participant who de-enrolls from any Stage 1 RTP Pilot rate will not be eligible to re-enroll until at least 12 months have elapsed since their prior de-enrollment from their Stage 1 RTP Pilot rate. The Settling Parties agree that a customer's initial enrollment in any Stage 1 RTP Pilot rate shall not be considered to constitute a "rate change" for purposes of Rule 12 (i.e., the customer will be allowed to change to another rate schedule during the first 12 months of the Pilot); except that residential customers who receive the Smart Panel incentives, as described in Appendix A, Attachment C, will be subject to their opt-in rate change being a Rule 12 change if the customer seeks to unenroll in the first year of the Pilot.[11/]

d. The Settling Parties agree that PG&E shall make its best efforts to program the three Stage 1 RTP Pilot rates and make them available for enrollment by October 1, 2023. The three Stage 1 RTP Pilot rates will remain available for the Pilots' 24-month period unless extended by the Commission when it acts on the Interim Evaluation Report AL as described above in Section V.B.3. In any case, the Settling Parties agree that no Stage 1 RTP Pilot rate should be launched during the Summer season (i.e., between June 1 and October 1) of any year.

e. The Settling Parties agree that eligible customers may enroll in the Stage 1 RTP Pilot rates at any time during the Pilots' 24-month period as described above in Section V.B.3. Participants will not be required to enroll at or before the time any of the Stage 1 RTP Pilot rates are launched but may enroll by opting into one of the Stage 1 RTP Pilot rates at any time during Pilots' 24-month period.

5. RTP Pricing Dissemination

The Settling Parties agree that the Pricing Tool and Communications Platform will be provided as proposed in PG&E's March 2021 testimony, Exhibit PG&E-RTP-1, pp. 5-16 to 5-19. The Settling Parties further agree that pricing will be disseminated to the CEC's MIDAS Platform, when it becomes available.

6. Design of Real Time Rate, MEC and MGCC

The Settling Parties agree that the RTP element of the Stage 1 RTP Pilot rates will replace the generation component of the customer's OAT schedule. The remaining transmission, distribution, Public Purpose Program (PPP) and other charges and taxes remain the same as the

11/ Residential Stage 1 RTP Pilot participants that receive a Smart Panel incentive will be required to remain on the Pilot rate for one year.

OAT. The Settling Parties agree that the RTP rate element will have the following components: a Marginal Energy Cost charge (MEC), a Marginal Generation Capacity Cost charge (MGCC), and a Revenue Neutral Adder (RNA). The RNA rate design is discussed below in Section V.B.7.

a. MEC: The Settling Parties agree that the MEC for the Stage 1 RTP Pilot rates will use the day-ahead hourly price from the California Independent System Operator (CAISO) Day Ahead Market (DAM), adjusted for energy line losses, determined at the PG&E Default Load Aggregation Point (DLAP). The issue of MEC methodology and development was uncontested in the parties' testimony.

b. MGCC: The Settling Parties agree that the MGCC component will be an hourly RTP generation component that recovers, on an average forecasted basis over the course of a year, the annual MGCC determined in the main track of PG&E's 2020 GRC Phase II proceeding, plus a capacity loss factor and a Planning Reserve Margin (PRM) factor. The specific calculation of the MGCC component will be determined following the completion of the MGCC study described below.

The Settling Parties are aware that a Stipulation regarding the scope, approach and schedule for a MGCC study to determine the structure for the Stage 1 RTP Pilot rates' MGCC component has already been reached (by Cal Advocates, SBUA and PG&E) in the Commercial Electric Vehicle Day-Ahead Hourly RTP (DAHRTP-CEV) proceeding (A.20-10-011). That Stipulation, which was received into evidence as Exhibit 20 in the DAHRTP-CEV proceeding, A.20-10-011, is attached hereto as Appendix B, Attachment A. The Settling Parties are aware that the Stipulation in A.20-10-011, proposed to include the MGCC study results in the record for that proceeding. The Settling Parties agree that the MGCC issues to be studied in A.20-10-011 and A.19-11-019 are identical and that there should be only one such MGCC study prepared for use in both proceedings.

The Settling Parties agree that the MGCC component should be cost-based and identical for whatever customer classes receive RTP rate options. Thus, for administrative efficiency, these MGCC issues should only be decided once by the Commission to ensure consistency on MGCC rate elements across A.19-11-019 and A.20-10-023. Accordingly, in a motion, to be filed under separate cover in A.19-11-019, the Settling Parties are also supporting PG&E's request for a prompt ruling from the Assigned Administrative Law Judge approving the recommendation to combine consideration of the identical remaining MGCC study issues under a single procedural schedule, in whatever manner can be most expeditious. By supporting the Motion, the Settling Parties seek to avoid duplicative parallel consideration of identical MGCC Study issues, to ensure efficient use of the parties' and the Commission's scarce resources as well as consistency in the Commission's treatment of MGCC issues across PG&E's various pending rate proceedings.

The Settling Parties agree that they can participate in the MGCC study to the extent they wish through whatever combined process for consideration of the MGCC Study is established (such as whatever the Assigned ALJ may decide in ruling on the above-referenced Motion, to be filed under separate cover in A.19-11-019).[12/]

12/ A suggested schedule for the presentation of MGCC Study results and resulting MGCC proposals had been included in PG&E Exhibit 22 in A.20-10-011. However, the CPUC's final decision in that proceeding (D.21-11-017) set a schedule for presentation of the MGCC study and for service of opening, reply and rebuttal testimony. That schedule had assumed that the necessary data would be received from Energy Division by August 2021, to allow sufficient time to submit the Study for presentation January 18, 2022. However, initial data was not received until September 24, with additional necessary data received on November 9, November 17, and November 23 of 2021. The Schedule outlined in Exhibit PG&E-22 (from A.20-10-011 for CEV RTP for Schedule BEV, [386579738.pdf (ca.gov)]) turned out to be infeasible primarily because the delivery of all necessary data from Energy Division was delayed by nearly three months. The Subject Matter Experts (SMEs) appreciate Energy Division's provision of data in request to their responses given Energy Division's significant workload with the IRP and IDER proceedings, among others. However, only after receiving and examining the final dataset in late November did the Study participants have confidence that they had received the best-available data from Energy Division that could be used to complete the study. Study participants have been working diligently since

Specifically, in the DAHRTP-CEV proceeding, PG&E has already been ordered to conduct and serve this MGCC Study on January 18, 2022. The December 17, 2021 Amended Scoping Memo in A.20-10-011 also established that, based on this MGCC Study, opening testimony would be submitted on or about February 21, 2022, with rebuttal testimony due March 11, 2022, to be followed by hearings if necessary, briefing and a Commission decision. Interested parties may also submit stipulations instead of, or in addition to, testimony. On January 6, 2022, PG&E filed a motion in A.20-10-011 to extend the procedural dates for the MGCC study and related testimony by eight weeks.

The Settling Parties agree that time is of the essence for Commission action resolving the issues addressed in this MGCC study, because the final MGCC detailed methodology is needed for inclusion in the RTP rates under both A.20-10-011 and A.19-11-019. The Settling Parties support the schedule proposed in the eight-week extension request as the best way to meet that goal, for the reasons described in the MGCC Study Procedural Dates Extension Request Motion. If the Assigned ALJs find that limited hearings are necessary on any contested issues of fact arising out of the MGCC Study, the Settling Parties request that they be completed on the schedule in the motion, which allows for final Commission action in the fourth quarter of 2022. The Settling Parties further agree that any such combined hearings should not litigate any issues other than the limited issues related to the development of the MGCC methodology or its allocation to hours. The Settling Parties agree to request that the Assigned ALJ issue an interim ruling as promptly as possible in January 2022, confirming that the resolution of these identical MGCC issues in A.19-11-019 and A.20-10-011 will proceed on a combined basis, under the same amended schedule requested for adoption for A.20-10-011. The Settling Parties agree that the DAHRTP-CEV MGCC study results and related testimony

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receiving the first, incomplete data in September, and now believe that the final report can be produced in a shorter period than the 5-6 months originally estimated, but no earlier than mid-March 2022.

shall also be received into the record of this GRC Phase II proceeding, to allow for a consistent resolution of these MGCC issues in both proceedings.

While the Settling Parties acknowledge that the Commission has previously declined to consolidate all RTP issues in A.20-10-011 and A.19-11-019, the Settling Parties nonetheless now agree that, for the limited issue of the MGCC study, consolidation is warranted at this time because these limited MGCC Study issues are identical and considering them at the same time will result in both administrative efficiencies as well as consistency. The Settling Parties believe that it would be appropriate for the assigned ALJ in A.19-11-019 to issue a ruling that the MGCC study and related MGCC issues will be litigated jointly for both proceedings through the schedule recommended for adoption in the above-reference Motion in A.20-10-011, and instructing all parties interested in such MGCC issues to participate in that consolidated MGCC process.

7. Design of Real Time Rate, Revenue Neutral Adder (RNA)

The Settling Parties agree to the following definition: the RNA is an additional rate component on top of the Energy and Capacity components that is designed to make the forecasted annual generation revenue collected under RTP rates revenue neutral to the forecasted annual generation component of the base rate schedules included in the Stage 1 RTP Pilots.

The Settling Parties agree that the RNA for the PG&E Stage 1 RTP Pilots' rate design will include TOU adjustments to make each TOU period revenue neutral to the base schedule. However, the RNA adjustment will be specific to each of the three Stage 1 RTP Pilot rate schedules, given that each will correspond to a separate OAT. Therefore, if, for any of these three rates, that differentiation would cause the peak period to have a lower RNA adder than the off-peak period, a flat RNA will be used for that rate schedule.

The agreed illustrative RNA values for the candidate Stage 1 RTP Pilot rates that have been discussed by parties in settlement meetings, are presented in Table 1 below, and are differentiated among the TOU periods on a per kWh basis and based on revenue requirements for the underlying rate used in the 2020 GRC Phase II (May 1, 2020 effective rates). The actual RNA values on implementation will be updated with revised revenue requirements, marginal costs, load profiles, and the final MGCC value (pursuant to decisions in A.19-11-019) and methodology before implementation.

Table 1: Illustrative Time-Varying Revenue Neutral Adders, by Schedule ($/kWh)

	E-ELEC	B-6	B-20
Summer Peak	0.01824	0.00519	0.05680
Summer Part Peak	0.01824	N/A	0.02387
Summer Off Peak	0.01824	0.00519	0.02025
Winter Peak	0.01824	0.00519	0.03001
Winter Part Peak	0.01824	N/A	N/A
Winter Off Peak	0.01824	0.00519	0.01740
Winter Super-Off Peak	N/A	0.00519	0.01416

The Settling Parties agree that the RNA adder includes a component for the non-time varying Renewable Energy Credit (REC) charge.

It is expected that the Power Charge Indifference Adjustment (PCIA) will no longer be included in Bundled service customers' generation rates at the time the Stage 1 RTP Pilots are implemented (per D.21-11-016 adopting settlements relating to the PCIA, presented in A.19-11-019, PG&E's 2020 General Rate Case Phase II). However, if at the time the Stage 1 RTP Pilots are implemented, PCIA rates have not yet been unbundled from Bundled service customers' generation rates, the non-time varying PCIA rates for each schedule will be added to the RNA to be used during the Stage 1 RTP Pilots.

8. Revenue Requirement Changes Between GRCs

The Settling Parties agree that, for revenue requirement changes between GRCs, adjustments to the RNA will be made on an equal cents basis to each TOU period to maintain revenue neutrality to the underlying rate. The methodologies for calculating the MEC and MGCC components will not change with revenue requirement changes between GRCs.

To the extent PG&E's marginal costs are updated for electric rate design purposes, such as the resolution of remaining issues in this GRC Phase II or PG&E's next GRC Phase II if decided during the operations of either of the Stage 1 RTP Pilots, PG&E will file, by Tier 1 AL (Tier 1 Marginal Cost Update AL), an updated tariff that ensures the MGCC, REC, and RNA reflect the new adopted marginal costs. As discussed above in Section V.B.7., the PCIA will be included in the RNA if the PCIA is still a part of the OAT generation rate.

9. Price Protections

The Settling Parties agree that, for the two agreed upon C&I Stage 1 RTP Pilot rates (on the B-6 and B-20 rate schedules) there should not be any price protections (such as price caps or bill protection beyond any price cap that may be instituted for the MGCC portion of the rate). However, for the one agreed upon rate to be tested in the Residential Stage 1 RTP Pilot (on the E-ELEC rate schedule), the Settling Parties agree that the Commission should adopt bill protection as set forth in in the description of the Residential Stage 1 RTP Pilot, attached hereto as Appendix A, Attachment C.

10. Customer Incentives

a. C&I Stage 1 RTP Pilot

The Settling Parties agree that no incentives will be paid to any participant in the C&I Stage 1 RTP Pilot.

b. Residential Stage 1 RTP Pilot

The Settling Parties agree that limited incentives should be tested for participants in the Residential Stage 1 RTP Pilot as follows and described in further detail in Appendix A, Attachment C:

i. Participation incentives will be provided only to the first 1,000 E-ELEC customers who enroll in the Residential Stage 1 RTP Pilot, but any customer eligible for E-ELEC will be eligible to enroll in the Pilot, even if the 1,000 customer cap on participation incentives has been reached.

ii. An additional Smart Panel incentive shall only be available to up to 250 Residential Stage 1 RTP Pilot participants.

11. Marketing, Education and Outreach

Outreach to potential Stage 1 RTP Pilot participants will include information alerting them that the Stage 1 RTP Pilots are designed to operate for a period of 24 months, and that participants may be returned to their OAT at the conclusion of the Pilots' 24-month period, or later, depending on the Commission's action on the Tier 2 Interim Evaluation Report AL which may request authority to extend one or more of the Pilot rates beyond the Pilots' 24-month period. The Tier 2 Interim Evaluation Report AL is expected to be filed approximately 18 months after the Stage 1 RTP Pilots are launched and is further discussed above in Section V.B.13.

The Settling Parties agree that PG&E's outreach shall focus on customers with energy management systems, energy managers, storage systems, electric vehicle charging, heat pump space heating and/or heat pump water heating, and/or high consumption during peak load periods.

The Settling Parties agree that PG&E will make program-specific marketing content available upon request to third parties and CCAs, for customer acquisition and support.

12. Dual Participation

The Settling Parties agree that dual participation shall be prohibited between Stage 1 RTP Pilot rates and load management approaches or demand response (DR) programs that are dispatched or otherwise based on day-ahead price signals or have energy-based payments (including ELRP, CESP, PDP, DRAM, and CBP). Dual Participation is also not allowed between the Stage 1 RTP Pilot rates and programs that are dispatched based on day-of conditions such as BIP, or that have day-of options such as ELRP.[13/]

13/ The Emergency Load Reduction Program (ELRP) is a five-year pilot program administered by PG&E that offers participants financial incentives to reduce energy usage during times of high grid stress and emergencies, with the goal of avoiding rotating outages while minimizing costs to customers. The CPUC ordered the Investor-Owned Utilities to administer ELRP in Rulemaking (R.) 20-11-003.

The Settling Parties agree that the issue of Dual Participation between day-ahead RTP rates and day-of Demand Response programs will be considered in the Interim Evaluation Report. If PG&E determines it is able to mitigate some of the technical difficulties in doing so, PG&E will permit limited dual participation on BIP and/or the day-of option for ELRP and the Stage 1 RTP Pilot to further evaluate impacts, including: 1) isolating ex-post and ex-ante BIP/ELRP RTP load impacts from dually participating customers so they can be correctly attributed to each program, 2) BIP resource forecasting and counting (i.e., bidding into the CAISO market, RA planning, etc.), 3) double compensation, and 4) generation revenue over-collection and under-collection.

13. Reporting Metrics, Measurement and Evaluation (Interim, and Final)

a) Reporting Metrics

The Settling Parties agree that those among them who are interested shall jointly develop reporting metrics to measure the success of the Stage 1 Pilots.

i. No later than 120 days after the decision, PG&E will hold a workshop to elicit parties' ideas about metrics for evaluation, and may hold further consultations if warranted. No later than 60 days after the workshop, PG&E will file a Tier 1 AL with the proposed evaluation plan including metrics (Tier 1 Proposed Metrics AL).

ii. In addition to metrics already recommended in PG&E's testimony (Ex. PG&E-RTP-1 pages 5-22 to 5-25), the reporting metrics will include factors that will inform the decision as to whether any of the Pilot rates will be continued beyond the Pilots' 24-month period and metrics to consider Dual Participation issues as described above.

iii. The final evaluation report will include a discussion of the potential for self-selection bias with cautions that the average expected savings per customer that might be expected from broader customer participation in the program would likely be lower than the level measured for the study group, which will inform the decision as to whether any of the Pilot rates will be continued beyond the Pilots' 24-month period.

iv. Program costs will be reported on a cost per participant basis wherever possible. Program cost metrics will be tracked on a fixed as well as a variable basis (e.g., per participant). The Settling Parties acknowledge that some costs considered "fixed," may actually vary depending on the number of participants and may not be fixed if the program were scaled from a pilot to standard rate options. PG&E agrees that it will identify costs of those type by the completion of the Final Evaluation Report.

b) Measurement and Evaluation Studies

The Settling Parties agree that PG&E shall perform two measurement and evaluation studies: i.) an interim evaluation to be completed at ~18 months based on the Stage 1 Pilots' first 12 months of data, and ii.) a final evaluation based on the full 24 months of Pilot operations (whether or not any of the Pilot rates are extended beyond the Pilots' 24-month period). See Appendix A, Attachment E for a timeline of Stage 1 RTP Pilot Measurement and Evaluation Studies, and Pilot Duration and Ending.

i. <u>Interim Evaluation Report and Advice Letter</u> - As discussed above in Section V.B.3. above, the Settling Parties agree that PG&E shall file a Tier 2 Interim Evaluation Report AL expected to be approximately 18 months after all three of the RTP rates approved for the Stage 1 RTP Pilots have been launched. This AL will recommend as to whether any of the rates included in the Stage 1 RTP Pilots should remain available beyond the Pilots' 24-month period.

The Interim Evaluation Report AL will include the most comprehensive reporting possible regarding the adopted metrics, within the available time, based on the available data from the first 12 months of each Stage 1 RTP Pilot's operations. The Settling Parties recognize that, because the Interim Evaluation Report AL must be prepared in a short time and based on whatever impact information is then available, this Report may not be comprehensive, as adequate data on all reporting metrics, described above, may not necessarily be available in time to prepare the Interim Evaluation Report AL by the agreed deadline.

The AL shall request Commission action within 90 days, if possible. However, if the Commission has not acted on that AL within 120 days, the Settling Parties agree that PG&E will notify the Commission and all Parties that the Pilot Rates will be extended at least an additional 90 days beyond the Pilots' 24-month period (which is 8 months after the Interim Evaluation Report AL will be filed), to allow PG&E adequate lead-time to complete its notifications to customers of the revised date on which they may be returned to the non-RTP version of their OAT.

ii. Final Evaluation Report and Advice Letter - Settling Parties agree that PG&E will publish a comprehensive Final Measurement and Evaluation Report after the end of the Stage 1 RTP Pilots (Tier 1 Final Evaluation Report AL) and a recommendation as to whether or not to continue any of the Pilot rates at broader scale. PG&E anticipates the Final Evaluation Report AL can be filed within eight months of the end of the Stage 1 RTP Pilots' 24-month period. As discussed above in Section V.B.3., if the Commission decides to continue the Pilot rates beyond the Pilots' 24-month period in response to the Interim Evaluation Report AL, the Settling Parties also agree that the Final Evaluation Report AL will include a recommendation on whether one or more of the RTP rates being tested should be continued on a broader scale. Stage 1 RTP Pilot participants will not be moved back to their OAT unless the Commission determines this outcome in response to the Final Evaluation Report AL. Stage 1 RTP Pilot participants can return to their OAT at any time if they so choose. In addition to the reporting metrics (as defined in the Tier 1 Proposed Metrics AL, discussed above), if PG&E recommends continuing any of the Pilot rates at broader scale, the Final Evaluation Report AL will also provide recommendations for changes or improvements for full scale implementation.

c. Other Measurement and Evaluation Terms

i. PG&E will engage qualified vendors to conduct the interim and final measurement and evaluation studies.

ii. If any other Load Serving Entities choose to offer programs or tariffs to Unbundled service customers based on rates produced by the Pilot, PG&E will make its best efforts to include the results of customer participation in those programs and tariffs in the interim and final evaluations.

14. Research Study for Residential, Agricultural and Small Business Customers

a. The Settling Parties agree that PG&E will conduct a Customer Research Study into dynamic pricing rate design and customer preferences for residential, small business and agricultural customers as described in PG&E's rebuttal testimony, Exhibit (PG&E-RTP-2), pages 1-7 to 1-9.

b. The Settling Parties agree that PG&E will conduct a workshop within 120 days of a Commission decision to define objectives and methods for the Customer Research Study.

c. PG&E may conduct further consultations with Settling Parties regarding the Customer Research Study if warranted.

15. Net Generator Output Meter (NGOM)

In PG&E's initial proposal, participants with a solar and storage installation would be required to have a separate NGOM, if their battery storage capacity is less than 10 kW. The purpose of the NGOM requirement for systems less than 10 kW was to avoid the need to estimate solar production by allowing actual metering to be relied on, instead, for calculating the value of the export and to determine the role of storage in response to RTP price signals. However, the Settling Parties now agree that participants with energy storage systems without separate metering between 1 kW and 10 kW instead will be required to agree to work with PG&E to convey hourly charge and discharge data on a monthly or quarterly basis. CALSSA will encourage energy storage companies to use best efforts to automate transmittal of customer level hourly charge and discharge data monthly or more frequently if possible. The Settling Parties agree that interval data is not required for storage less than 1 kW. For participants with battery systems with capacities greater than or equal to 10 kW the same metering already addressed in the NEM 2.0 tariff shall be used for the Stage 1 RTP Pilots.

16. Cost Recovery of Pilot Costs in Rates

The Settling Parties agree that all development, implementation and operating costs for the Stage 1 RTP Pilots, as well as for the separate Customer Research Study for residential, agricultural, and small business customers, will be tracked in the Dynamic and Real Time Memorandum Account (DRTPMA) for recovery in a future application and testimony.

The following 4 categories of costs will be recovered in distribution rates from all customers, allocated by the Equal Percent of Total revenue (EPT)[14/] allocation method:[15/]

14/ The EPT method is defined in the 2020 GRC Phase II Exhibit (PG&E-3), Chapter 2 and adopted in D.21-11-016 as part of the Revenue Allocation Settlement. It is an allocator in proportion to each class's total revenue with generation imputed for DA/CCA customers.

15/ The total cost estimate for the C&I Stage 1 RTP Pilot proposal was $7.776 million to $11.096 million (A.10-11-019, Exhibit (PG&E-RTP-1), p. 5-25, Table 5-5). The cost estimate for the Customer Research Study for residential and agricultural customers was $400,000 to $700,000 (PG&E-RTP-1, p. 1-45, lines 15 and 16). The additional cost estimate for the Residential Stage 1 RTP Pilot which was not included in PG&E's initial proposal in PG&E-RTP-1 is $1.807 million,

a. The costs for the Stage 1 RTP Pilots approved in A.19-11-019 (not including costs in d. and e. below).
b. The costs for the separate Customer Research Study for residential, agricultural, and small commercial customers approved in A.19-11-019.
c. DAHRTP-CEV rate program costs approved in D.21-11-017 (not including costs in d. and e. below).
d. Joint costs between the Stage 1 RTP Pilots and the DAHRTP-CEV rate program (e.g., joint costs for the Customer Enablement Platform and billing) (not including costs in a., b. or c. above).

In addition, the amount of bill protection payments for Bundled service residential customers participating in the residential RTP pilot will also be tracked in the DRTPMA for recovery in a future application and testimony. The cost of these bill protection payments will be related to the generation component on the Bundled service residential customer's bill. The rate component (e.g., distribution or generation) where these bill protection costs will be recovered, as well as the cost allocation methodology (whether EPT or some other cost allocation methodology), will be determined in the future application.

PG&E will record in the DRTPMA the actual costs it incurs pursuant to the Commission's orders for Dynamic and RTP Pilots and the separate Customer Research Study in A.19-11-019, (as well as already ordered in D.21-11-017 for the DAHRTP-CEV rate program). All recorded costs will be subject to reasonableness review, either through a future single application or proposal and testimony requesting cost recovery submitted by PG&E. PG&E agrees to record costs in the DRTPMA consistent with how costs have been recorded in its Residential Rate Reform Memorandum Account (RRRMA) established in D.15-07-001 for the

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as described in Appendix A, Attachment C. This amount does not include any bill protection payments for Bundled service customers.

implementation of residential default time of use rates. PG&E can recover the costs recorded to the DRTPMA only after the Commission finds that PG&E has demonstrated in the separate application or testimony that its expenditures were incremental, verifiable, and reasonable, and consistent with the requirements resulting from A.19-11-019 or D.21-11-017, as well as consistent with any other relevant Commission rulings and approvals (including, without limitation, plans and activities submitted by PG&E approved through advice filings discussed elsewhere herein).

17. Generation Revenue Over-collection and Under-collection (Revenue Requirement Recovery and Avoiding Double Collection)

The Settling Parties acknowledge that tracking generation costs and revenues associated with the RTP rate is extremely complicated and involves several PG&E balancing accounts. Therefore, the Settling Parties agree that the best course of action for the Stage 1 RTP Pilots is to track and study generation costs and generation revenues over the course of the Stage 1 RTP Pilots, with no predefined mitigation or revenue recovery procedures.

PG&E will study generation revenue over-collection and under-collection during the Stage 1 RTP Pilots, setting out metrics in the Measurement and Evaluation study described above in Section V.B.13. PG&E's generation revenue over-collection and under-collection study will attempt to differentiate between structural effects (i.e., due solely to enrollment and disenrollment) and rate-induced changes in customer energy use. PG&E will track each Pilot customer's load profiles, both before and after they began participating in any of the Stage 1 RTP Pilots rates and compare them to performance under non-RTP time-of-use rates as well as the aggregate load of customers not-participating in the Stage 1 Pilots. PG&E will identify those elements of the Energy Resource Recovery Account (ERRA) balancing account that may not be attributable to an RTP rate and will measure possible double counting of annual energy and capacity costs in Stage 1 RTP Pilot rates.

If the study results indicate material and systemic generation revenue over-collection or under-collection, PG&E and/or other Settling Parties may file a proposal to modify the RTP rate either during the Stage 1 RTP Pilots, or after their conclusion. The Settling Parties' initial conceptual plans for PG&E's generation revenue over-collection and under-collection study are presented in Appendix A, Attachment B.

C. Information Technology Billing Systems Changes and Timing

PG&E commits to implementing, as soon as practicable, whatever structural changes to PG&E's systems may be necessary to conduct the Stage 1 RTP Pilots agreed upon in this Settlement, including associated external systems for which PG&E is responsible. PG&E advises, and the Settling Parties acknowledge, that to achieve PG&E's goal of timely usability of the systems involved and necessary employee training, any proposed timeline may be modified. The Settling Parties agree that this Settlement Agreement shall not preclude any party's right to solicit action from the Commission to address unreasonable delays in implementation of the structural changes to PG&E systems necessary for the Stage 1 RTP Pilots. Prior to contacting the Commission regarding concerns about the timing of PG&E's implementation of the Stage 1 RTP Pilot rates, the Settling Parties agree to meet and confer with PG&E on the status of the Stage 1 RTP Pilots' implementation, discuss options for resolution and allow PG&E a reasonable time to pursue any viable alternative option.

Section V.B.4., above, sets forth the target date for PG&E to make best efforts to program and make available for enrollment the agreed upon Stage 1 RTP Pilot rates by October 2023, but if the Commission approves something other than what is included in this Settlement Agreement, roll-out of the Stage 1 RTP Pilot rates may take additional time beyond October 2023 and may require revised cost and timing estimates.[16/]

16/ Current cost estimates are summarized in Footnote 15.

VI. APPENDICES TO SETTLEMENT

The following lists reference the documents that are being included as Appendices and Attachments to this Settlement Agreement:

Appendix A

- Attachment A - Comparison Exhibit
- Attachment B - Generation Revenue Over-collection and Under-collection Study Concept
- Attachment C - Residential Stage 1 RTP Pilot Settlement Agreement
- Attachment D - Proposed and Potential Advice Letters for Stage 1 RTP Pilots Implementation
- Attachment E - Timeline of Stage 1 RTP Pilot Measurement and Evaluation Studies, and Pilot Duration and Ending

Appendix B

- Attachment A - Joint Stipulation on Study for MGCC Rate Design Issue, A.20-10-011, Exhibit PG&E-20, June 1, 2021.
- Attachment B - Motion of Pacific Gas and Electric Company for Ruling Revising the Schedule in the Assigned Commissioner's Amended Scoping Memo Issued December 17, 2021 for Marginal Generation Capacity Cost Study and Testimony, A.20-20-011, January 6, 2022.
- Attachment C - Declaration of Anh Dong in Support of PG&E on Residential Stage 1 Pilot Cost Estimates.

VII. SETTLEMENT EXECUTION

This RTP Settlement Agreement may be executed in separate counterparts by different Settling Parties hereto and all so executed will be binding and have the same effect as if all the Settling Parties had signed one and the same document. Each such counterpart will be deemed to be an original, but all of which together shall constitute one and the same instrument, notwithstanding that the signatures of all the Settling Parties do not appear on the same page of the RTP Settlement Agreement. This RTP Settlement shall become effective among the Settling Parties on the date the last Settling Party executes the RTP Settlement Agreement, as indicated below. In witness whereof and intending to be legally bound by the Terms and Conditions of this RTP Settlement Agreement as stated above, the Settling Parties duly execute this RTP Settlement Agreement on behalf of the Settling Parties that they represent, as follows:

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

Agricultural Energy Consumers Association

By: ________Michael Boccadoro_______

Michael Boccadoro

Title: _______Executive Director_______

Date: _______1/14/2022____________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

The Public Advocates Office at the California Public Utilities Commission

By: ______________________

Title: Deputy Director

Date: January 14, 2022

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

California Large Energy Consumers Association

Nora Sheriff

By: Nora Sheriff, Esq.

Title: Attorney

Date: January 13, 2022

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

Energy Producers and Users Coalition

Nora Sheriff

By: Nora Sheriff, Esq.

Title: Attorney

Date: January 13, 2022

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

Energy Producers and Users Coalition

By: ______________________________

Title: ______________________________

Date: ______________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

Federal Executive Agencies

By: Rita M Dittz

Title: COUNSEL, FEA

Date: January 13, 2022

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

California Solar and Storage Association

By: ______________________________

Title: ______________________________

Date: ______________________________

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

California Solar and Storage Association

By: [signature]

Title: Policy Director

Date: 1/14/22

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

Enel X North America, Inc.

By: Sara Steck Myers

Title: Attorney for Enel X North America, Inc.

Date: January 14, 2022

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

Ohm Connect, Inc.

By: ______________________

Title: General Counsel

Date: 1/13/2022

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

Pacific Gas and Electric Company

Robert S. Kenney

By: ______________________________

Title: Senior Vice President

Date: January 14, 2022

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

Pacific Gas and Electric Company

Robert S. Kenney

By: ______________________________

Title: Senior Vice President

Date: January 14, 2022

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2020 GRC Phase II RTP Settlement Agreement.

Small Business Utility Advocates (SBUA)

By: ______________________________

Title: __President and General Counsel_______

Date: ___Jan. 14, 2022____________________

APPENDIX A – ATTACHMENT A

APPENDIX A, ATTACHMENT A
PACIFIC GAS & ELECTRIC COMPANY
2020 GRC PHASE II (A.19-11-019) RTP TRACK SETTLEMENT AGREEMENT
COMPARISON EXHIBIT SHOWING PARTIES' PRE-SETTLEMENT POSITIONS
STAGE 1 PILOTS AND CUSTOMER RESEARCH STUDY

	Issues	**PG&E Testimony**	**AECA Testimony**	**Cal Advocates Testimony**	**CALSSA-ENEL X Testimony**	**CLECA Testimony**	**EPUC Testimony**	**FEA Testimony**	**SBUA Testimony**
1	Whether PG&E's proposal that the Stage 1 Pilot RTP rate to be optional with all Commercial and Industrial (C&I) customers eligible to participate is reasonable.	As presented in PG&E's *Supplemental Testimony PG&E-RTP-1, p. 5-1*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, p. 16*
2	Whether PG&E's proposal for C&I customers to be eligible for Stage 1 Pilot RTP rate offered in 2023 is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 5-8 to 5-9*	Unopposed	Support, *Cal Advocates-RTP-2, p. 7*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed
3	Whether PG&E's proposal to perform enhanced outreach to customers with energy management systems, energy managers, storage systems and/or high consumption during peak load periods is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 5-12 to 5-13; Rebuttal Testimony, PG&E-RTP-2, p. 6-2*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, p. 9*
4	Whether PG&E's proposal to provide collateral and indirect marketing support to third parties in enhanced outreach to target customers is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 5-15; Rebuttal Testimony,*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, p. 9*

		PG&E-RTP-2, pp. 6-6 to 6-7							
5	Whether PG&E's proposal that the Stage 1 Pilot RTP rate comprises an hourly energy charge, an hourly capacity charge and a revenue neutral adder (RNA) and is revenue neutral to the base rate schedules is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 4-1 to 4-2*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support *Responsive RTP Testimony, SBUA-RTP-01, p. 45*
6	Whether PG&E's proposal that the Stage 1 Pilot RTP rate's Marginal Energy Cost (MEC) component should be based on day-ahead hourly prices from the California Independent System Operator (CAISO) adjusted for line losses, determined at the PG&E Default Load Aggregation Point (DLAP) is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 3-5 to 3-9; Rebuttal Testimony, PG&E-RTP-2, p. 3-3*	Unopposed	Unopposed	Support, *Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 5-6*	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, pp. 17-18*
7	Whether PG&E's proposal that the Stage 1 Pilot RTP rate's MEC component should not be scaled by Equal Percent of Marginal Cost (EPMC) factors is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, p. 4A-2*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Direct Testimony, AECA-1, p. 29; pp. 30-31; Responsive RTP Testimony, SBUA-RTP-01, pp. 17-18*
8	Whether PG&E's proposal that there is no time differentiation of Power Charge Indifference Adjustment (PCIA) is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, p. 4A-4*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, p. 18*

9	Whether PG&E's proposal that the Stage 1 Pilot RTP rate will replace the generation component of the applicable rate schedule and the remaining transmission, distribution, Public Purpose Program (PPP) and other charges and taxes remain the same as the otherwise applicable rate is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 5-6, p. 1-49, Table 1-10, p. 4-1*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, pp. 17-18*
10	Whether PG&E's proposal that the MEC and MGCC methodologies should not change with revenue requirement changes between GRCs is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 4-AtchA-14 to 4-AtchA-15*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed
11	Whether PG&E's proposal that Net Energy Metering (NEM) customers should have their generation export compensation vary by hour with the Stage 1 Pilot RTP price, even if the price is negative, which would result in a charge and not a credit is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, p. 4A-3*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed
12	Whether PG&E's proposal that Reporting Metrics will be determined during the initial design and customer outreach phase of the Stage 1 Pilot is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 5-23 and 5-24*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed

13	Whether PG&E's proposal to solicit ideas on reporting metrics from parties in related proceedings (DAHRTP-CEV and GRC Phase II RTP) is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, p. 5-10*	Unopposed	Support, *Cal Advocates-RTP-1, pp. 19-20*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed
14	Whether PG&E's proposal to file a Tier 1 AL of the Reporting Metrics prior to launch of the State 1 Pilot is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, p. 5-10*	Unopposed	Support, *Cal Advocates-RTP-1, pp. 19-20*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed
15	Whether PG&E's proposal there be an Interim Evaluation Report (first year results) and Final Measurement and Evaluation Report, including Reporting Metrics is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 5-8; Rebuttal Testimony, PG&E-RTP-2, p. 5-10*	Unopposed	Support, *Cal Advocates-RTP-1, pp. 19-20*	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01*, *p. 11*
16	Whether PG&E's proposal regarding a Pricing Calculation Tool and Communications Platform, as proposed in PG&E's March 2021 testimony, is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 5-17 to 5-19*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, p. 17*
17	Whether PG&E's proposal that eligible customers can enroll in the RTP rate at any time even after the pilot is launched during the pilot duration when the rate is available is reasonable.	As presented in PG&E's *Supplemental Rebuttal, PG&E-RTP-2, p. 5-3*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, p. 11*
18	Whether PG&E's proposal to limit participation to two CCA	PG&E's *Supplemental Testimony,*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony,*

	or ESPs who will mirror[1] PG&E RTP rate structure but Participation by unbundled customers will depend on their LSE, a CCA or ESP, joining the pilot, which cannot be required is reasonable.	*PG&E-RTP-1, p. 5-10*							*SBUA-RTP-01, p. 16*
19	Whether PG&E's proposal that the pilot would be available to commence by summer 2023 is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 1-1, p. 1-50, Table 1-10, p. 5-8*	Unopposed	Unopposed	Oppose, Recommend that PG&E aim to make the rate live outside of the peak summer months, likely in Fall or Winter 2023. *Supplemental Testimony CALSSA-ENELX-RTP-1, p. 5*	Unopposed	Unopposed	Unopposed	Unopposed
20	Whether PG&E's proposal to do a research study into agricultural preferences and dynamic pricing rate design is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 1-1 to 1-2, pp. 1-44 to 1-45*	Unopposed	Support, *Cal Advocates-RTP-2, pp. 9-10*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed
21	Whether PG&E's proposal to do a research study into residential preferences and dynamic pricing rate design is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 1-2, pp. 1-42 to 1-44*	Unopposed	Support, *Cal Advocates-RTP-1, pp. 12-13 and Cal Advocates-RTP-2, pp. 9-10*	Oppose, *Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 2-4 8; Rebuttal Testimony CALSSA-ENELX-*	Unopposed	Unopposed	Unopposed	Unopposed, *Responsive RTP Testimony, SBUA-RTP-01, p. 3*

[1] Replacing generation prices with CAISO Day Ahead prices and a capacity adder.

					RTP-2, pp. 1, 3-4, 5-6				
22	Whether PG&E's proposal that the Marginal Generation Capacity Cost (MGCC) component should be based on the annual Marginal Capacity Cost determined in the main track of PG&E's GRC 2020 Phase II proceeding, plus potentially a loss factor and a Planning Reserve Margin (PRM) factor, times a factor that can vary by hour is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 4-AtchA-7; Rebuttal Testimony, PG&E-RTP-2, p. 3-3*	Unopposed	Support, but proposed different components for the MGCC portion, see *Cal Advocates-RTP-1, pp. 5-11*	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01*, *pp. 17-18*
23	That PG&E, Cal Advocates, SBUA, and other interested parties should conduct a research study to establish how various definitions and combinations of PCAF-based and AWE-based hourly MGCCs correlate with reliability metrics such as Loss of Load Expectation (LOLE), Expected Unserved Energy (EUE), and/or reserves shortfalls.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, p. 3-3*	Unopposed	Support, *Cal Advocates-RTP-2, pp. 4-7*	Unopposed, *Supplemental Testimony CALSSA-ENELX-RTP-1, p. 6*	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01*, *p. 30*
24	Whether the Stage 1 Pilot rate should include separate components for MEC and MGCC.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 4-1 to 4-2; Rebuttal Testimony,*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony SBUA-RTP-01*, *pp. 17-18*

		PG&E-RTP-2, p. 3-2							
25	Whether PG&E's proposal that at least some of the hourly-varying MGCC factor should be based on a Peak Capacity Allocation Factor (PCAF) calculated from Adjusted Net Load (ANL) over the entire CAISO system is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 4-AtchA-8 to 4-AtchA-10; Rebuttal Testimony, PG&E-RTP-2, p. 3-3*	Unopposed	Support, but proposed modifications to the PCAF calculations, see *Cal Advocates-RTP-1, pp. 5-8*	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, pp. 17-18*
26	Whether PG&E's plan to file a Tier 2 Advice Letter after the interim evaluation indicating whether or not PG&E recommends continuing the Stage 1 Pilot beyond the 24 months is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, p. 5-9*	Unopposed	Unopposed	Opposed, Recommend that an ongoing rate be put in place (expanded to B1-ST and residential customers) that will be studied annually while it is ongoing which would commence one year after the first customer is enrolled. *CALSSA-ENEL X, Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 4-5, 8; CALSSA-ENEL X, Rebuttal Testimony CALSSA-ENELX-*	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, p. 11*

					RTP-2, pp. 1, 3-4, 5-6				
27	Whether PG&E's proposal that Stage 1 Pilot RTP rate should be a pilot lasting 24 months, with potential to extend and participants will be returned their otherwise applicable tariff at its conclusion is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 1-42, Table 1-8, p. 1-50, Table 1-10, p. 5-8; Rebuttal Testimony, PG&E-RTP-2, pp. 5-6 to 5-7 and p. 5-9*	Unopposed	Unopposed	Opposed, CALSSA-ENEL X, Supplemental Testimony *CALSSA-ENELX-RTP-1, pp. 1, 4-5, 8;* CALSSA-ENEL X, Rebuttal Testimony *CALSSA-ENELX-RTP-2, pp. 1, 3-4, 5-6*	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01*, *pp. 10-12*
28	Whether, if PG&E decides to extend the Stage 1 Pilot, PG&E's proposal to file an Advice Letter with recommendations for RTP rates beyond the 24-month Pilot Period along with recommendations for changes or improvements is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, p. 5-9*	Unopposed	Unopposed	Opposed, CALSSA-ENEL X, Supplemental Testimony *CALSSA-ENELX-RTP-1, pp. 1, 4-5, 8;* CALSSA-ENEL X, Rebuttal Testimony *CALSSA-ENELX-RTP-2, pp. 1, 3-4, 5-6*	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01*, *p. 11*
29	Whether PG&E's proposal to provide Stage 1 Pilot customers with generation costs consistent with PG&E's bill presentment for all other customers is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, pp. 5-10 to 5-13*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed
30	Whether PG&E's proposal that the C&I RTP Pilot Rate be available on the C&I B-19 and	As presented in PG&E's *Supplemental*	Unopposed	Support, *Cal Advocates-RTP-2, p. 7*	Unopposed	Unopposed	Unopposed	Unopposed	Support, but also recommend all rate schedules,

	B-20 rate schedules is reasonable.	*Testimony, PG&E-RTP-1, pp. 1-3 to 1-4; Rebuttal Testimony, PG&E-RTP-2, p. 1-3*							B1-ST and B-6 at a minimum, *Responsive RTP Testimony, SBUA-RTP-01*, *pp. 7-8*
31	Whether PG&E's proposal to prohibit dual participation on other load management approaches is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 1-AtchA-3; PG&E-RTP-2, pp. 2-1 to 2-9*	Unopposed	Support, *Cal Advocates-RTP-2, pp. 12 – 13*	Opposed, Recommend that dual participation in RTP be allowed for customers that participate in load management offerings that provide non-overlapping signals, especially the Base Interruptible Program (BIP). *Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 6-7, 8; Rebuttal Testimony CALSSA-ENELX-RTP-2, pp. 2, 4-5*	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01*, *p. 17*
32	Whether PG&E's proposal that the Stage 1 Pilot should have no participation cap is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 1-49, Table 1-10, p. 5-7, Table 5-*	Unopposed	Unopposed	Opposed, Propose ongoing RTP rate with an enrollment cap for different customer classes, with C&I	Unopposed	Unopposed	Unopposed	Unopposed, *Responsive RTP Testimony, SBUA-RTP-01*, *p. 16*

		2; Rebuttal Testimony, PG&E-RTP-2, p. 5-3, p. 5-6			enrollment capped at 2,000 total customers and residential customers capped at 3% of total customers. *Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 4-5, 8*				
33	Whether PG&E's plan to alert Stage Pilot Participants that the pilot is expected to end is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, p. 5-9*	Unopposed	Unopposed	Opposed, *CALSSA-ENEL X, Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 4-5, 8; CALSSA-ENEL X, Rebuttal Testimony CALSSA-ENELX-RTP-2, pp. 1, 3-4, 5-6*	Unopposed	Unopposed	Unopposed	Unopposed
34	Whether PG&E's proposal to conduct a workshop within 60 days of a CPUC decision to define objectives and methods for rate design and preferences research is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 1-43, p. 1-44, Table 1-9, p. 1-50, Table 1-10*	Unopposed	Support, *Cal Advocates-RTP-1, p. 13.*	Opposed, *CALSSA-ENEL X, Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 4-5, 8; CALSSA-ENEL X, Rebuttal Testimony CALSSA-ENELX-RTP-2, pp. 1, 3-4, 5-6*	Unopposed	Unopposed	Unopposed	Unopposed

35	Whether PG&E's proposal not to expand the Stage 1 pilot to residential (E-TOU-D, EV2, E-ELEC, and E-DER) is reasonable until research is completed.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 1-33 to 1-37; Rebuttal Testimony, PG&E-RTP-2, pp. 1-5 to 1-6*	Unopposed	Support, *Cal Advocates-RTP-1, pp. 12-13 and Cal Advocates-RTP-2, pp. 8-10*	Opposed, *CALSSA-ENEL X, Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 4-5, 8; CALSSA-ENEL X, Rebuttal Testimony CALSSA-ENELX-RTP-2, pp. 1, 3-4, 5-6*	Unopposed	Unopposed	Unopposed	Unopposed
36	Whether PG&E's proposal not to expand the Stage 1 Pilot to small business specific rates (B-1-Storage, B-6 and B-10) is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, pp. 1-20 to 1-21*	Unopposed	Support, *Cal Advocates-RTP-1, pp. 12-13 and Cal Advocates-RTP-2, pp. 8-10*	Opposed, *CALSSA-ENEL X, Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 2-5, 8; CALSSA-ENEL X, Rebuttal Testimony CALSSA-ENELX-RTP-2, pp. 1, 3-4, 5-6*	Unopposed	Unopposed	Unopposed	Opposed, Recommend all rate schedules, B-6 at a minimum, *Responsive RTP Testimony, SBUA-RTP-01, pp. 7-8; Rebuttal RTP Testimony, SBUA-RTP-02, pp. 7-15*
37	Whether the C&I RTP Pilot should consider the participation of and particular interests of small businesses, who may have different challenges and capabilities than large businesses.	As presented in PG&E's *Supplemental Testimony, Rebuttal Testimony, PG&E-RTP-2, pp. 6-7 to 6-9*	Unopposed	Oppose, *Cal Advocates-RTP-2, pp. 8-10*	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, pp. 4-9*
38	Whether PG&E's proposal to not develop an agricultural rate similar to the voluntary dynamic pricing schedule PA-RTP offered by Southern	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1,*	Oppose, Proposal presented in AECA's *Direct Testimony of*	Support, *Cal Advocates-RTP-1, pp. 12-13 and Cal Advocates-RTP-2, pp. 8-10*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed

	California Edison is reasonable.	*pp. 1-38 to 1-40; Rebuttal Testimony, PG&E-RTP-2, pp. 1-23 to 1-25*	*Richard J. McCann, PhD, AECA-1, pp. 49-50*						
39	Whether PG&E's proposal to include customers of the NEM successor tariff from R.20-08-020 in the Stage 1 Pilot is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 5-7, Table 5-2; Rebuttal Testimony, PG&E-RTP-2, p. 1-21*	Unopposed	Opposed, see *Cal Advocates-RTP-2, p. 12*	Support, *CALSSA-ENEL X, Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 7-9*	Unopposed	Unopposed	Unopposed	Unopposed
39	Whether PG&E's proposal for the components of MGCC are reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 3-9 to 3-12; Rebuttal Testimony, PG&E-RTP-2, pp. 3-14 to 3-23*	Unopposed	Proposed a hydro-adjustment to the PCAF calculation plus CPP component, see *Cal Advocates-RTP-1, pp. 5-11*	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01*, *pp. 18, 37*
40	Whether PG&E's proposal for the RNA calculation methodology is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, pp. 4A-3 to 4A-6, 4B-2 to 4B-7*	Unopposed	Unopposed, but requested study of potential double counting issues, *Cal Advocates-RTP-2, pp*. 13-16	Opposed, *CALSSA-ENEL X, Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 1, 6, 8*	Unopposed	Unopposed	Unopposed	Opposed, *Responsive RTP Testimony, SBUA-RTP-01*, *pp. 44-50; Rebuttal RTP Testimony, SBUA-RTP-02, pp. 18-22*
41	Whether PG&E's proposal to recover incremental costs through distribution rates and	As presented in PG&E's *Supplemental*	Unopposed	Opposed, Proposed equal cents allocation,	Unopposed	Support, CLECA's *Rebuttal*	Support, EPUC's *Rebuttal Testimony,*	Support, FEA's *Rebuttal Testimony FEA-*	Opposed, Agree with Cal Advocates'

	allocated using the standard distribution allocator is reasonable.	*Testimony, pp. 1-45 to p. 1-46; Rebuttal Testimony, PG&E-RTP-2, p. 4A-7, pp. 4A-10 to 4A-11*		see *Cal Advocates-RTP-1, pp. 14-18*		*Testimony, CLECA-RTP-1, pp. 5-7*	*EPUC-RTP-01, p. 3, lines 4-7*	*RTP-1, p. 3, lines 11-12*	recommendation to recover incremental costs through the PPP charge, *Rebuttal RTP Testimony, SBUA-RTP-02*, *pp. 15-16*
42	Whether PG&E's decision to study under- and over-collections rather than proposing a rate design solution for over- and under-collections by Pilot participants is reasonable.	As presented in PG&E's *Supplemental Testimony, p. 1-27, Table 1-4, p. 4-4; Rebuttal Testimony, PG&E-RTP-2, p. 4A-10*	Unopposed	Opposes, *Cal Advocates-RTP-1, p. 19*	Unopposed	Oppose, *CLECA's Rebuttal Testimony, CLECA-RTP-1, pp. 7-8*	Unopposed	Unopposed	Unopposed, *Responsive RTP Testimony, SBUA-RTP-01, p. 17; Rebuttal RTP Testimony, SBUA-RTP-02*, *p. 17*
43	Whether PG&E's proposal there be no price protection or pilot incentives is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, p. 5-7, Table 5-2*	Unopposed	Unopposed	Opposed, *CALSSA-ENEL X, Supplemental Testimony CALSSA-ENELX-RTP-1, pp. 3-4*	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01*, *p. 17*
44	Whether PG&E's proposal not to formally include a "kill switch" or "exit ramp" for a natural disaster or other event is reasonable.	As presented in PG&E's *Rebuttal Testimony, PG&E-RTP-2, pp. 4A-13 to 4A-14*	Unopposed	Unopposed	Opposed, CALSSA-ENEL X, Supplemental Testimony *CALSSA-ENELX-RTP-1 pp. 3-4;* CALSSA-ENEL X, Rebuttal Testimony *CALSSA-ENELX-RTP-2, p. 6-7*	Unopposed	Unopposed	Unopposed	Unopposed

45	Whether the amount of increased rate and bill volatility inherent in PG&E's proposed RTP rate design is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 3-18 to 3-22*	Unopposed	Opposed, see *Cal Advocates-RTP-1, pp. 5-8*	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01*, *pp. 12-14*
46	Whether PG&E's proposal to record incremental costs in the Dynamic and Real-Time Pricing Memorandum Account (DRTPMA) is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 1-45 to 1-46; Rebuttal Testimony, PG&E-RTP-2, p. 4A-7*	Unopposed	Unopposed	Unopposed	Oppose, CLECA's *Rebuttal Testimony, CLECA-RTP-1, p. 2-4*	Unopposed	Unopposed	Unopposed
47	Whether PG&E's proposal that the Net Generation Output Metering (NGOM) be required for NEM eligible generators for sites with onsite solar generation and battery storage of less than 10kW is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 5-9 to 5-10, Rebuttal Testimony, PG&E-RTP-2, pp. 5-4 to 5-6*	Unopposed	Unopposed	Opposed, CALSSA-ENEL X, Supplemental Testimony *CALSSA-ENELX-RTP-1, pp. 1, 7-9*	Unopposed	Unopposed	Unopposed	Unopposed
48	Whether PG&E's proposal for the ME&O plan is reasonable.	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 5-11 to 5-16; Rebuttal Testimony, PG&E-RTP-2, pp. 6-1 to 6-9*	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Unopposed	Support, *Responsive RTP Testimony, SBUA-RTP-01, p. 9*

49	Whether cost allocation be addressed in a future rate case or another proceeding is reasonable	As presented in PG&E's *Supplemental Testimony, PG&E-RTP-1, pp. 1-45 to 1-46*	Unopposed	Oppose, *Cal Advocates-RTP-1, pp. 14-17*	Unopposed	Support, *Rebuttal Testimony, CLECA-RTP-1, p. 4*	Support, EPUC's *Rebuttal Testimony, EPUC-RTP-01, p. 5, lines 9-15*	Support, *FEA Rebuttal, FEA-RTP-1, p. 3, lines 8-10*	Unopposed

APPENDIX A -ATTACHMENT B

APPENDIX A, ATTACHMENT B
PACIFIC GAS & ELECTRIC COMPANY
2020 GRC PHASE II (A.19-11-019) RTP TRACK SETTLEMENT AGREEMENT
BACKGROUND AND CONCEPTUAL DETAILS OF PG&E'S GENERATION REVENUE OVER AND UNDER-COLLECTION STUDY

1. Overall Study Objectives

- PG&E will study over- and under-collection during the Stage 1 Pilots, setting out metrics in the Measurement and Evaluation study.
    - PG&E will track customer load profiles before and after going on RTP, RTP Prices compared to TOU prices, and aggregate load profiles of non-participating customers within that class.
    - PG&E will study changes in billed revenue for the E-ELEC pilot customers by comparing the customers' billed revenue under the RTP rate option to billed revenue for customers on the otherwise applicable tariffs (OAT). Specifically, PG&E will compare the test group monthly revenues, by customer, to the control group revenue in an effort to identify whether the RTP rate design is truly revenue neutral. Parameters of the comparison will take into consideration the customer's usage level as well as baseline territory in an effort to minimize climate location differences. Parties agree that this study may not represent a complete picture of potential cost shifts as a result of the RTP rate. PG&E's RTP rate has a unique feature (RNA) intended to mitigate cost shift. A representative cost shift study would need to consider other factors such as the differences in the utility cost of service between the test and control groups. As explained in PG&E's March 29, 2021 testimony (PG&E-RTP-1, p. 27), PG&E does not believe a cost-shift study is warranted for the Stage 1 RTP Pilots, given that standard TOU rates already cause a cost shift and that RTP rates are more cost-based than TOU rates, and customers on RTP may reduce overall cost shifts, even if their usage is different from forecasts.
- PG&E's study will attempt to differentiate over- and under-collection effects between structural effects (i.e., due solely to enrollment and disenrollment) and rate-induced changes in customer energy use.
- PG&E will identify those elements of the Energy Resource Recovery Account (ERRA) balancing account that may not be attributable to an RTP rate and will measure possible double counting of annual energy and capacity costs in Stage 1 Pilot customers' rates.

2. Generation Rate Energy Costs

   - PG&E will track the actual CAISO cost to serve load incurred to serve bundled customers, and recorded to ERRA Line Item 5.l, as shown below, and compare to the forecast cost to serve load.[1] The comparison of forecast to actuals will be on a $/kWh basis, which compares the actual CAISO cost to service load to the forecast rate for CAISO charges, which are used to forecast a portion of PG&E's generation rate.

   - Any variance in the forecast cost to serve load compared to the actual cost to serve load will be reflected in the end-of-year balance in ERRA. Given the end-of-year balance in ERRA informs the RTP RNA, PG&E plans to study the potential for double collection related to variances between forecast energy prices and actual recorded energy prices.

     - PG&E will compare RTP MEC revenues with the actual cost to serve RTP customers rather than comparing RTP revenues with the OAT revenues whenever possible. OAT generation rates are set in advance, using forecasted prices and usage, and the differences between actual energy prices and forecast energy prices will inform any proposal for adjustment of the RTP RNA.

3. Generation Capacity Costs - Background

   - A portion of PG&E's portfolio capacity costs are recovered through generation rates and a portion of the capacity costs are recovered through PG&E's generation-related non-bypassable charges (NBCs).

   - PG&E's two primary NBCs whereby a portion of PG&E's capacity costs can be recovered include: (1) the vintaged Power Charge Indifference Amount (PCIA) rate and (2) the New System Generation Charge (NSGC). The PCIA is recorded to the Portfolio Allocation Balancing Account (PABA) and New System Generation Balancing Account (NSGBA).

   - Of note, capacity costs recorded to ERRA are imputed based on Commission approved Market Price Benchmarks for system, local, and flexible resource adequacy values. Any residual capacity costs that remain in PABA are considered unsold and would be valued at zero. Capacity costs associated with new procurement will be recovered through either the PCIA or the NSGC.

     - Beginning in 2021, an increasing portion of new mandated procurement is recovered through PG&E's NSGC, which recovers procurement costs that support system and local reliability where these resources have been

[1] See PG&E's Electric ERRA Preliminary Statement CP: www.pge.com/tariffs/electricpreliminary/assets/pdf/tariffbook/ELEC_PRELIM_CP.pdf

designated to be eligible for the Cost Allocation Mechanism (CAM). CAM-eligible resource costs are recorded to PG&E's NSGBA.

  - Beginning in 2023, the Central Procurement Entity (CPE) will be procuring resources for local reliability and those resources will be recovered through the NSGC and recorded to the NSGBA.

  - The integrated resource planning process recently ordered PG&E to procure over 2000 MW of new resources beginning in 2023. These resources have been designated to be PCIA-eligible and will be recovered through vintaged PCIA rates.

4. Generation Capacity Costs - Commitments

- PG&E will track the forecast and actual capacity costs included in PG&E's generation rate and PG&E's generation-related NBCs.

- PG&E will monitor capacity costs that are forecast and recovered through the ERRA, NSGC, and vintaged PCIA rates and will track actual capacity costs recorded to the account in an effort to assess how capacity costs are recovered through PG&E's generation rate, PCIA, and NSGC, and how much variance may be reflected in the balancing account balance each year.

  - As with energy revenues, PG&E will compare RTP MGCC revenues with the actual cost to serve RTP customers rather than comparing RTP revenues with the OAT revenues whenever possible. This is more difficult for capacity as there is no real-time capacity market. The capacity portion of OAT generation rates are set in advance, using forecasted prices and usage. The proposed analysis will also address variances that may be embedded in PG&E's generation rate and other generation-related NBCs in order to assess whether adjustments are needed to avoid double counting capacity costs paid for by RTP customers through their capacity charge.

- PG&E will track customer load profiles before and after going on RTP, RTP prices compared to TOU prices, and aggregate load profiles of non-participating customers.
- In this study, PG&E will use its best efforts to attempt to differentiate whether any over- and/or under-collection effects resulted from structural effects (i.e., solely due to enrollment/disenrollment) and/or rate-induced changes in customer energy use.

ATTACHMENT C

APPENDIX A, ATTACHMENT C
PACIFIC GAS & ELECTRIC COMPANY
2020 GRC PHASE II (A.19-11-019) RTP TRACK SETTLEMENT AGREEMENT
RESIDENTIAL STAGE 1 RTP PILOT SETTLEMENT AGREEMENT

Section V.B.2.a. of the GRC Phase II RTP Settlement Agreement (Settlement Agreement) provides that there shall be no more than three rate schedules included in any Stage 1 RTP Pilot. Settling Parties agree that two rate schedules will be included in a C&I Stage 1 RTP Pilot (B-6 and B-20),[1] and one rate schedule will be included in a Residential Stage 1 RTP Pilot (E-ELEC, which was adopted in Decision (D.) 21-11-016[2]). PG&E's March 29, 2021 GRC Phase II supplemental testimony provided PG&E's proposal for the high-level parameters and cost estimates for the C&I Stage 1 RTP Pilot,[3] which have been modified and further clarified in the Settlement Agreement. As agreed upon by the Settling Parties, this Appendix provides high-level parameters and cost estimates for the Residential Stage 1 RTP Pilot. In addition, please see Appendix B, Attachment C for a declaration by Witness Anh Dong in Support of PG&E's Residential Stage 1 Pilot Cost Estimates.

I. Background

PG&E originally proposed to pilot RTP for large C&I customers and to defer residential RTP until after research could be conducted on the best path forward for any new dynamic rates offerings for its residential customer class. PG&E based its proposal on the benchmarking research that it conducted on RTP in the United States. The benchmarking results showed 53 active non-residential RTP rate schedules offered by regulated U.S. utilities wherein some large C&I customers provide load response to support the electricity grid. The benchmarking study identified only two residential RTP rates (both offered in Illinois) which both have very low enrollment, plus briefly mentioned the risk and challenges recently experienced by residential customers on RTP in Texas. (Exhibit PG&E-RTP-1, dated March 29, 2012, pages 1-1 to 1-2,

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1 No Option R or Option S versions of the rates will be included. Settling Parties have agreed that after the initial launch of the Stage 1 RTP Pilots, if PG&E determines that it has become logistically feasible to implement and include other rate schedules (e.g., Schedule B-19, and Option R and Option S within Schedules ~~s~~ B-19 and B-20), PG&E may file a Tier 1 Advice Letter (AL) to add those rate options to the Stage 1 RTP Pilots (Tier 1 Supplemental Rates AL).

2 D.21-11-016, pp. 108-115.

3 A.19-11-019, Exhibit (PG&E-RTP-1), Chapter 5.

and page 1-21.) Therefore PG&E's initial proposal was to focus on larger C&I customers for its Stage 1 RTP Pilot.

PG&E has continued to monitor developments in California involving RTP, which have recently suggested a faster timeline for introducing a residential RTP pilot might be desirable:

1. The California Energy Commission (CEC) is moving forward with Load Management Standard revisions which call for each utility to submit a proposal to its rate-approving body for at least one hourly or sub-hourly marginal cost rate for each customer class within one year of the effective date of the regulations, which are expected to be adopted February 8, 2022, which could result in a potential March 1, 2023 deadline for RTP rate proposals, including for the residential customer class.[4]
2. In parallel with the CEC's Load Management Standard revisions, the California Public Utility Commission's (CPUC's) draft Distributed Energy Resource (DER) Action Plan 2.0 aims for RTP pilots for all customer classes by 2024.[5]
3. Certain parties have and are currently advocating for residential RTP pilots in Southern California Edison's (SCE) and San Diego Gas & Electric's (SDG&E) GRC Phase 2 proceedings.
4. A recent CPUC decision (D.21-12-015) in the Emergency Reliability Order Instituting Rulemaking ((R.) 20-11-003) authorized an RTP pilot for Unbundled service Valley Clean Energy (VCE) agricultural irrigation customers in PG&E's service territory, despite a minimal rate design record regarding the non-generation rate component, hypothesizing that RTP could help the electrical grid.[6]

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4 Proposed Regulatory Language for the Load Management Standards Regulations (California Code of Regulation Title 20 § 1623(a), within the Load Management Rulemaking (19-OIR-01), December 22, 2021. Expected to be adopted February 8, 2022. file:///C:/Users/E1B4/Desktop/TN241068_20211222T073008_Proposed%20Regulatory%20Language.pdf

5 Draft CPUC DER Action Plan 2.0, Aligning Vision and Action. July 23, 2021, p. 8, Vision Element 1A, Action Element 3: "By 2024, all utility customer classes have access to multiple rate options, including dynamic and RTP rate pilots that are informed by focus group research and supported by ME&O programs to match various customer preferences and engagement levels. SMJUs and CCAs are encouraged to provide the same for their customers."

6 D.21-12-015, p. 86.

This rulemaking also authorized SCE to expand a dynamic rate pilot to all customer classes.[7]

5. D.21-12-015 also authorized the inclusion of residential customers in certain groups for the Emergency Load Reduction Program (ELRP), which is not integrated into the CAISO, to help support the grid when it is stressed.[8]
6. D.21-11-017 did not adopt Enel X's proposal to expand the Business Electric Vehicle Real Time Pricing rate (DAHRTP-CEV) to 500 residential customers,[9] but noted that RTP is being considered for other customer classes in this track of PG&E's GRC Phase 2 proceeding, A.19-11-019.[10]

The Settling Parties have recognized, in balance, that including a residential rate schedule as part of PG&E's Stage 1 RTP Pilot is likely to produce valuable data regarding residential customer behavior, which when combined with the additional qualitative research regarding residential RTP, will more fully inform Commission decision-making regarding: (1) the future development of dynamic price offerings for the residential class, and (2) the cost effectiveness of dynamic price offerings for residential customers.

II. Goals and Guiding Principles for the Residential Stage 1 RTP Pilot

The Residential Stage 1 RTP Pilot with Schedule E-ELEC is intended to test the following hypotheses:

1. Residential customers can adjust electricity usage to respond to hourly price signals.
2. Automated control technology is needed for residential customers to effectively respond to price signals (and what type of control technology may be most effective).
3. Controlling different technologies separately is less effective than controlling all of the technologies simultaneously at the main electrical panel of the house. (To

[7] D.21-12-015, p. 98.
[8] D.21-12-015, Attachment 2, specifically added group 6 to ELRP for residential customers.
[9] A.20-10-011, ENELX-01, p. 6, lines 6-9.
[10] D.21-11-017, p. 29 and p. 34.

test this type of control, the Parties agree to incentivize Smart Panel[11] installation, as described below in Section III.2.b.)

4. Enabling a residential RTP price signal would incent the control software market to develop more sophisticated technology for the residential market.
5. There can be incremental beneficial load response from residential customers on RTP compared to the load response from residential customers on time-of-use (TOU) rates.
6. The benefits of the incremental load response from RTP outweigh the costs of enabling participation in the Stage 1 RTP Pilot through incentives and bill protection.
7. Residential customers are willing to stay on an RTP rate without bill protection.

III. Basic Elements for the Residential Stage 1 RTP Pilot

The Residential Stage 1 RTP Pilot has the following elements:

1. Eligibility
    a) The residential Schedule E-ELEC will be used to demonstrate RTP, which can be elected by any residential customer meeting its eligibility terms. However, participation incentives will be provided only to the first 1,000 customers who enroll in the Residential Stage 1 RTP Pilot. Most of these customers will be on the RTP version of E-ELEC, with a smaller number, as a control group, receiving the E-ELEC TOU price signal and bill (without an RTP price signal).
    b) The Residential Stage 1 RTP Pilot will prioritize recruitment of customers with the following home technologies: EVs, batteries, and heat pumps (for space heating and/or water heating).

[11] Smart Panels allow customers choose which loads to be powered at any time and control each individual household circuit.

2. Incentives

   There will be two types of incentives:

   a) Participation Incentives: $300 per customer for up to the first 1,000 customers who enroll. Customers will receive this $300 incentive in three installments of $100 each at the following milestones:

      i. Sign-up;

      ii. After completion of first-year survey; and

      iii. After completion of end-of-pilot survey.

   b) Technology Incentives for Smart Panels: $1,625 per / panel for up to 250 customers, resulting in total incentives of $406,250. Due to the limited number of Smart Panels currently in the market, the Parties are agreeing to provide incentives to defray a portion of the cost of the panels. This incentive will enable testing of the hypothesis that controlling the major appliances (e.g., EVs, batteries, heat pump technologies) in a house, each with a different control technology, is less effective than controlling the entire house with a single control technology. Customers who receive the Smart Panel incentives ideally would remain on the Pilot for its entire duration. Therefore, approximately 75% of the Smart Panel incentives ($1,225) will be paid at the beginning of the Pilot, and the remainder ($400) will be paid upon customer completion of the first-year survey. Furthermore, as discussed in the Settlement at Section 4.c., residential customers who receive the Smart Panel incentives will be subject to their opt-in rate change being a Rule 12 change if the customer seeks to unenroll in the first year of the Pilot.

   c) Only one residential RTP rate, an RTP version of E-ELEC, will be tested in PG&E's Residential Stage 1 RTP Pilot. This untiered TOU rate plan was designed to encourage electrification by residential customers. Moreover, it is simpler to optimize an untiered price signal, like E-

ELEC's, than a tiered price signal (i.e., one where prices increase when consumption exceeds certain amounts).

3. Sample Cells

Customers will be randomly assigned to either:

a) The test group – which will receive the E-ELEC RTP price signal and bill, and,

b) A control group – who will receive the E-ELEC TOU price signal and bill (and no RTP price signal).

The total number of customers in each sample cell will not be equal and the test group will be larger than the control group. PG&E intends to structure the sample in such a way to be sufficient to test all hypotheses outlined above.

4. CCA / DA Participation

Any participating Community Choice Aggregator (CCA) / Direct Access (DA) provider will set their own RTP day-ahead hourly generation energy rate, just like they will for the C&I Stage 1 RTP Pilot rates also being jointly proposed in the Settlement Agreement, and the DAHRTP-CEV optional RTP rate for Electric Schedule BEV adopted in D.21-11-017.

5. Price Dissemination

The Pricing Tool and Communications Platform will be provided as proposed in PG&E's March 2021 testimony, Ex. PG&E-RTP-1, pp. 5-16 to 5-19. Pricing will also be disseminated to the CEC MIDAS Platform when it becomes available.

6. Bill Protection

The inherent price volatility involved with being on an RTP rate is believed likely to discourage most residential customers from participating in this pilot. Even residential customers who already have control technology for major equipment (such as batteries or EVs), would be exposing their overall household usage to price volatility under the RTP Pilot. The Settling Parties agree that one year of bill protection may be necessary to overcome residential customers' hesitancy to participate in the Residential Stage 1 RTP Pilot.

a. To encourage residential customers in the test group on the RTP rate to stay in the Pilot for a full year, bill protection will be paid at the end of the customer's first year on the Pilot, which will provide those customers ample time to become more familiar with RTP. If a customer unenrolls from the Residential Stage 1 RTP Pilot before the end of their first year, they would forfeit bill protection. Customers in the test group on the TOU rate will not receive bill protection. Customers beyond the initial 1,000 enrolled will not be provided bill protection.

b. Discontinuing bill protection after one year allows for an evaluation not only of unenrollments due to the discontinuation of bill protection, but also of the performance of remaining customers who continue on the residential RTP rate longer than one year, to assess whether customer behavior and load impact differed depending on whether their participation was with or without bill protection.

c. PG&E is not able to estimate at this time the cost of the bill protection provision, because Schedule E-ELEC's RTP hourly pricing will depend on future volatility in the California Independent System Operator (CAISO) hourly day-ahead (DAM) market which will determine the hourly MEC rate component, and other factors that will influence the size of the hourly MGCC rate component. Even if PG&E were to roughly estimate what percentage of load might get shifted into the lower priced period due to the Residential Stage 1 RTP Pilot, it is not possible to predict CAISO hourly DAM price volatility from 2023 through 2025 (the duration of this pilot) with enough precision to develop a reliable cost estimate.

IV. Cost Information

PG&E provides the following information on certain elements of costs for the Residential Stage 1 RTP Pilot that are incremental to the costs estimated in PG&E's initial C&I Stage 1 RTP

Pilot proposal submitted on March 29, 2021in PG&E's supplemental GRC Phase II RTP testimony. These estimates of incremental cost may not be comprehensive, in that other costs might later emerge as being necessary for operating the Residential Stage 1 RTP Pilot. The Settling Parties agree that the costs for the Residential Stage 1 RTP Pilot will be entitled to recovery under the same terms agreed to in Section V.B.16. of the Settlement Agreement. The estimated incremental costs (above those set forth in PG&E's March 20, 2021 proposal) resulting from the addition of the Residential Stage 1 RTP Pilot are estimated to be a total of $1,806,250 consisting of:[12]

a. Marketing Education & Outreach - $350,000
b. Incentives - $706,250
c. Measurement and Evaluation - $500,000
d. Program Administration - $250,000 (for one added FTE to provide operational support)

The addition of this Residential RTP Pilot will not cause any incremental costs for billing system modifications or to the cost of the Pricing Tool and Communications Platform, as the cost to program a third RTP pilot rate in those systems can be accommodated within the range of costs already presented in PG&E's March 29, 2021 proposal.[13]

The amount of Bill Protection that will be paid to participants is unknown as explained above in Section III.6, and will be in addition to the $1,806,250 incremental cost estimate above.

Section V.B.16. of the Settlement Agreement describes the proposed method for recovering all C&I and Residential Stage 1 RTP Pilot costs, including Bill Protection payments.

Please see Appendix B, Attachment C for a declaration by Witness Anh Dong in Support of PG&E's Residential Stage 1 Pilot Cost Estimates.

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[12] A.19-11-019, Exhibit (PG&E-RTP-1), p. 5-25, Table 5-5. The total cost estimate range for C&I Stage 1 RTP Pilot with two large C&I rate schedules was $7.776 million to $11.096 million. PG&E also estimated the cost of the residential and agricultural rate design and preferences study between $400,000 and $700,000 (p. 1-45, lines 15 and 16).

[13] A.10-11-019, Exhibit (PG&E-RTP-1), p. 5-25, line 1 and line 5. The range of the forecast for the Pricing Tool and Communications Platform (Customer Enablement) is $1.0 million to $1.3 million. The range of the forecast for incremental billing system modifications is $4.6 million to $6.9 million.

ATTACHMENT D

APPENDIX A, ATTACHMENT D
PACIFIC GAS & ELECTRIC COMPANY
2020 GRC PHASE II (A.19-11-019) RTP TRACK SETTLEMENT AGREEMENT
PROPOSED / POTENTIAL ADVICE LETTERS

Advice Letter Title	Tier	Timeline / Triggers
Supplemental Rates	1	If PG&E determines that it has become logistically possible after the launch of the Stage 1 Pilot - no specific timeline needed.
Metering Eligibility	2	Within 120 Days of the NEM 2.0 Successor Tariff decision.
Interim Evaluation Report	2	When Interim Evaluation Report is completed, expected to be ~18 months after launch of the Stage 1 RTP Pilot rates depending on inclusion of summer and winter months.
Marginal Cost Update	1	At resolution of remaining marginal cost issues in 2020 GRC Phase II and/or final decision in 2023 GRC Phase II if needed - no specific timeline needed.
Proposed Metrics	1	No later than 60 days after completion of Metrics Workshop/Consultations (which will be held no later than 120 days after a decision in this case).
Final Evaluation Report	1	End of Stage 1 Pilot - no specific timeline needed.

ATTACHMENT E

APPENDIX A, ATTACHMENT E
PACIFIC GAS & ELECTRIC COMPANY
2020 GRC PHASE II (A.19-11-019) RTP TRACK SETTLEMENT AGREEMENT
TIMELINE OF STAGE 1 RTP PILOT MEASUREMENT AND EVALUATION STUDIES, AND PILOT DURATION AND ENDING

		2023			2024												2025												2026							
Month	**Timing**	**O**	**N**	**D**	**J**	**F**	**M**	**A**	**M**	**J**	**J**	**A**	**S**	**O**	**N**	**D**	**J**	**F**	**M**	**A**	**M**	**J**	**J**	**A**	**S**	**O**	**N**	**D**	**J**	**F**	**M**	**A**	**M**	**J**	**J**	**A**
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Stage 1 Pilots	Months 1-24 (24 Months)												Y1																							
Interim Evaluation (first 12 months of Pilot data)																																				
Data Gathering and Analysis	Months 14-17 (4 months)																																			
Interim Evaluation Report AL with recommendation on extending any rate(s) (90-day response requested)*	Month 18 (1 month)																																			
Scenario 1 - Commission responds to AL in <120 days	Months 19-22 (4 months)																																			
• *Outcome A* : Pilot rate(s) ended	Month 25 (1 month)																																			
• *Outcome B* : Pilot rate(s) extended until determination of Final Evaluation Report**	Month 25-35+ (11 months)																																			>>
Scenario 2 - Commission responds in 120 to 240 days	Months 25-28 (4 months)																																			
• *Outcome C:* End Date is extended 90 days (notify Commission)	Months 25-28 (4 months)																																			
Communicate to Customers Pilot end date or extension details	Month 24 (1 month)																																			
Final Evaluation (24 months of Pilot data)																																				
Data Gathering and Analysis	Estimated Timing																																			
Final Evaluation Report AL with recommendation to continue any rate(s)	Estimated Timing																																			

AL = Advice Letter
*If necessary, PG&E submits request to modify timeline due to unanticipated events that delay the Interim Evaluation Report AL or Interim Evaluation is inconclusive.
**Timelines for further continuing or ending Pilot rate(s) to be included in Final Evaluation Report AL.

APPENDIX B

APPENDIX B – ATTACHMENT A
Joint Stipulation on Study for MGCC Rate Design Issue, A.20-10-011, Exhibit PG&E-20, June 1, 2021.

Application No.: A.20-10-011
Exhibit No.: PG&E-20
Date: June 1, 2021

Joint Stipulation on Study for MGCC Rate Design Issue

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39M) for Approval of its Proposal for a Day-Ahead Real Time and Pilot to Evaluate Customer Understanding and Supporting Technology.	Application 20-10-011 (Filed October 23, 2020)

Joint Stipulation on Study for MGCC Rate Design Issue

I. INTRODUCTION

PARTIES STIPULATING: The parties sponsoring this stipulation are the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Small Business Utility Association (SBUA), and Pacific Gas and Electric Company (PG&E) (together Stipulating Parties). Cal Advocates and SBUA have authorized PG&E to submit this stipulation on their behalf consistent with Rule 1.8 (d) of the Commission's Rules of Practice and Procedure.

SCOPE OF STIPULATION: The Stipulating Parties have taken different positions in this proceeding regarding the development of a marginal generation capacity cost (MGCC) component for a real time rate to be used in PG&E's pilot for commercial electric vehicles, the DAHRTP-CEV pilot (CEV Pilot). The Stipulating Parties have entered into this stipulation to make clear their support for a research study (Study) to analyze the relationship of the following variables to the condition of the CAISO grid: 1) hydro year conditions, 2) the definition and weighting of the hydro variable in the calculation of Adjusted Net Load (ANL), 3) CAISO restricted maintenance operations (RMO), 4) day-ahead CAISO Flex Alerts and CAISO alerts events, 5) other CAISO warning and emergency events,

6) the Peak Capacity Allocation Factor (PCAF) threshold, and 7) the functional form of PCAF weighting above the PCAF threshold,[1] using SERVM data that Energy Division would provide. The Stipulating Parties believe that the analyses will provide useful information to inform the development of the MGCC element of a real time pricing (RTP) rate for the CEV Pilot, and also of the MGCC element for the RTP pilot for Commercial and Industrial (C&I) customer being considered in the RTP track of PG&E's GRC Phase II (the GRC II Pilot). The Stipulating Parties agree that it is very important that the findings of the Study, when complete, be included in the record and considered by the Commission in its determination of the MGCC element for the real-time rate design in this proceeding.

II. STIPULATED STUDY

PG&E has used its generation peak capacity allocation factor (PCAF) method to develop generation rates for TOU rates and allocate MGCC among customer classes in revenue allocation for several years,[2] based on adjusted net load (ANL)[3] above a threshold. PG&E's ANL/PCAF method includes a hydro variable in the definition of ANL and uses all weather year scenarios in the calculation of the threshold and the "PCAF denominator." Cal Advocates has proposed to reflect different hydro year assumptions than used by PG&E, by limiting the selection of weather years used to calculate both the PCAF threshold and the PCAF denominator in the MGCC allocation to those simulated weather years with similar hydro conditions to the current year.

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1 This refers to the shape of the PCAF risk curve above the PCAF threshold, such as whether the risk curve should increase linearly with increasing adjusted net load (ANL) or if it would more accurately match the underlying hourly capacity risk by using a non-linear function.

2 There is only one customer class in the DAHRTP-CEV pilot. Therefore, allocation among customer classes is not relevant for purposes of the pilot in A.20-10-011.

3 ANL refers to system-level metered load net of all solar and wind generation, small and large hydro, nuclear, geothermal, biomass and biogas generation. None of the Stipulating Parties contest the general use of PG&E's ANL/PCAF method for these purposes.

Cal Advocates and SBUA also each propose a different adjustment for how MGCC would be allocated to hours. Cal Advocates proposes to assign 13 percent[4] of the MGCC to the hours 3-9pm during which CAISO issues a day-ahead Flex Alert or alert (CAISO alert) and only for hours for which PG&E's PCAF-based capacity prices do not meet or exceed a certain threshold, possibly with limits on the minimum and maximum number of hours called in each calendar year. The remaining MGCC value (87 percent of total)[5] would be assigned to hours based on PG&E's PCAF methodology. SBUA proposes to allocate the MGCC based on CAISO Flex Alerts, CAISO RMOs, and an ANL/PCAF method based on PG&E's hydro assumptions or with Cal Advocates hydro year modification, potentially using a different functional form for PCAF weighting above the threshold than PG&E's linear function, and/or using a different threshold than PG&E's 80 percent of scenario-averaged maximum annual ANL.

The Stipulating Parties agree that their different approaches are reasonable to evaluate, but that insufficient data is currently available to support more than a hypothetical evaluation of parties' different MGCC allocation proposals in terms of whether one proposal or some combination of the proposals would produce the best alignment with underlying hourly capacity shortfall risk for the CAISO system – which is essential to the construction of a meaningful, cost-based capacity price signal in the DAHRTP rate.

To address the lack of data, SBUA has recommended PG&E perform a Study quantifying the relationship between various alternative forms of its PCAFs and reliability metrics.[6] PG&E recognizes the value of such a Study and proposes including

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[4] That is, Cal Advocates proposes to assign the marginal capacity costs associated with the 15% planning reserve margin (PRM) to an hourly capacity component based on CAISO Alerts and Flex Alerts. 15% / 115% = 13.04%.

[5] 100%-13%. See footnote 4.

[6] *See* SBUA Direct Testimony, pp. 11-12.

further variables in the Study such as 1) the definition of the hydro variable,[7] 2) the weighting of the hydro variable,[8] 3) variations of Cal Advocates' reliability Capacity Peak Pricing (reliability CPP) or CAISO Alert-Based Adjustment (CABA) proposal, as discussed in PG&E's rebuttal testimony,[9] and 4) SBUA's proposed inclusion of RMOs.

To perform the Study, PG&E will need system-wide historical and/or forecasted hourly capacity shortfall (reliability) metrics such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE), Expected Unserved Energy (EUE), and/or reserves shortfalls data, which PG&E believes is available through SERVM data which the Commission's Energy Division retains.[10] Upon delivery of this data to PG&E, the study can likely be completed within five to six months, with participation by Cal Advocates, and SBUA.[11]

It would also be valuable to the Study to obtain more detailed information from CAISO regarding the standards that it applies to initiate an Alert, Warning or Emergency (AWE) event, both in general and with respect to historical events. Among the actions and efforts that the CAISO, CPUC and CPUC are taking to prepare California for extreme heat waves without having to resort to rotating outages, "[t]he CAISO, CPUC, and CEC are planning to enhance the efficacy of Flex Alerts to maximize consumer conservation and other demand side efforts during extreme heat events."[12]

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7 For instance, PG&E's marginal energy cost (MEC) model currently uses a 25-day rolling average of average daily hydro generation and daily maximum hydro generation. The averaging (25-day, daily) and type (average or maximum) may need to be changed to most accurately represent hydro's contribution to capacity needs. *See* PG&E Rebuttal Testimony, pp. 2-8:18-28 to 2-9:1-6.

8 PG&E's MEC model currently applies a 1.19 weighting factor to the hydro variable, based on a calibration using all hours from 2012 to 2019. However, PG&E believes that a weighting factor less than one may be more appropriate to model capacity risk, as hydro capacity is less dependent on annual inflow volume than is annual hydro energy.

9 *See* PG&E Rebuttal Testimony, p. 2-13:8-11.

10 *See* PG&E Rebuttal Testimony, p. 2-9:20-25.

11 PG&E states the study would require the first half of 2022. *See* PG&E Rebuttal Testimony, p. 2-9:14-17.

12 CAISO, CPUC, and CEC, *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave* (January 13, 2021), pp. 1-2.

III. GOALS OF THE STUDY:

The purpose of the Study is to determine the fit between alternative formulations of hourly MGCC, as described above or as developed during the Study, and capacity shortfall (reliability) metrics.[13] The primary purpose of a real-time capacity price signal is to accurately reflect temporal (hourly) variations to the risk that there will be insufficient capacity to serve demand – and thus variations in the capacity costs at the margin of serving incremental load. The Stipulating Parties agree that the Study will provide a data-driven benchmark of which real-time capacity pricing proposals, or combinations thereof, most closely align with hourly capacity shortfall risk and with the costs PG&E incurs to serve marginal load. This would enable the DAHRTP pilot rate to send more effective forecast generation capacity price signals, increasing the potential benefits of the CEV Pilot. A more accurate generation capacity price signal could improve system reliability, and reduce the duration or magnitude of power outages during the extreme capacity shortfall events; and could also reduce cost shifting between participants and non-participants by ensuring that pilot participants pay as close as possible to the actual marginal costs incurred by PG&E (whether in the operating year or a subsequent year).

Additionally, the Study will help to identify the appropriate level of inter-annual variation in the DAHRTP pilot rate's MGCC price element. Parties' MGCC proposals result in differing levels of intra- and inter-annual variation in capacity prices.[14] By comparing the various proposals to reliability metrics and determining which proposals produce the best fit, the Study could indicate what level of intra- and inter-annual

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[13] *See* SBUA Direct Testimony p. 11:10-14 and PG&E Rebuttal Testimony, p. 2-9:1-6.

[14] See, for example, Table 1-8 on p. 1-27 of Cal Advocates' direct testimony comparing inter-annual variability in PCAFs between PG&E's and Cal Advocate's proposals under PG&E's 10 simulated weather years that comprise its 2021 DAHRTP rates forecast, and Figures 3 and 4 on pp. 17-21 of SBUA's reply testimony comparing highest priced hours between PG&E, Cal Advocates and SBUA proposals using PG&E's estimates of MEC and MGCC prices for 2017-2020.

variation is most appropriate and would most accurately capture varying levels of capacity shortfall risk within a year and across multiple years.[15]

IV. PROCEDURAL PROPOSAL

The Stipulating Parties would start work on the Study as soon as Energy Division makes the SERVM data available. Thereafter, the estimate for completion of the Study is 5 to 6 months. When the Study results are available, each Stipulating Party would use the results to develop its proposal for 1) allocation of the MGCC to hours, and 2) what factors should be used, e.g., CAISO Alerts, CAISO RMOs, and ANL/PCAF implementation.

Stipulating Parties' proposals can consider other criteria for inclusion of those factors into the MGCC price element of DAHRTP pilot rate, such as customer understandability and acceptance of the rate component. Other parties could also develop proposals for MGCC based on the results of the Study.

The Stipulating Parties would move for admission of the study results into the record of this proceeding. The Stipulating Parties anticipate that MGCC proposals allowed by this procedural step would be presented in in testimony, for decision by the Commission. The Administrative Law Judge could set limited hearings on the proposals, either on his or her own motion, or in response to a request by the Stipulating Parties for limited hearings on the MGCC proposals. Issues decided in the Commission decision for the DAHRTP-CEV pilot that are not related to the development of the MGCC or its allocation to hours, may not be relitigated in connection with this procedural process for the Study.

A key timing element is how soon the SERVM data can be obtained, i.e., the sooner the Study can begin, the sooner parties can provide their testimony on

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15 *See* PG&E Rebuttal Testimony p. 2-7:12-15.

incorporating the study results into the DAHRTP-CEV pilot rate. For this reason the Stipulating Parties have not included any specific dates in the Stipulation.

V. STIPULATING PARTIES' REQUEST FOR THE CURRENT JUNE 2021 PROCEEDINGS

The Stipulating Parties agree that a Commission decision based on the evidentiary record from the June 2021 hearings should not decide the MGCC issues addressed in this stipulation. The Stipulating Parties make this request to coordinate the inclusion of the study results and the preceding section IV Procedural steps in order to avoid confusion and potentially conflicting results if the MGCC issues to be studied were also addressed on the merits in a Commission decision on the upcoming June hearing record.

Allowing for inclusion and review of Study data in this proceeding prior to a Commission decision on MGCC design issues would reduce the likelihood that the Commission and parties will need to modify a decision reached without the benefit of Study data, should the Study findings warrant adjustment to the DAHRTP rate design.

The Stipulating Parties agree to waive cross-examination of their witnesses for the June 2021 hearings in A.20-10-011 on the MGCC issues covered by this Stipulation. The Stipulating Parties agree that each Stipulating Parties' testimony and cross-examination exhibits that have been served as of May 29, 2021 on the MGCC issues may go into the evidentiary record in A.20-10-011; but that the Stipulating Parties are not waiving their rights to cross-examine the witnesses on MGCC issues in future proceedings, including future proceedings that may address incorporation of the study results into the DAHRTP-CEV pilot rate.

The Stipulating Parties further request that in the Commission's decision in A.20-10-011, the Commission consider including the following findings:

1. The Commission finds that the Study will provide necessary data to set the MGCC element of the CEV RTP rate.

2. To perform the Study, PG&E will need system-wide historical and/or forecasted reliability metrics available through SERVM data which the Commission's Energy Division retains. Energy Division is directed to take the appropriate steps to provide the SERVM data to PG&E, and to allow parties participating in the Study to see the data, if necessary after signing a Non-Disclosure Agreement.

3. If additional information regarding standards that CAISO applies to initiate an Alert, Warning or Emergency (AWE) event can be obtained from the CAISO, both in general and with respect to historical events, the additional information may be useful input into development of the MGCC element of the real time rate.

APPENDIX B – ATTACHMENT B

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39M) for Approval of its Proposal for a Day-Ahead Real Time Rate and Pilot to Evaluate Customer Understanding and Supporting Technology	Application 20-10-011 (Filed October 23, 2020)

MOTION OF PACIFIC GAS AND ELECTRIC COMPANY FOR RULING REVISING THE SCHEDULE IN THE ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO ISSUED DECEMBER 17, 2021 FOR MARGINAL GENERATION CAPACITY COST STUDY AND TESTIMONY

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Dated: January 6, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39M) for Approval of its Proposal for a Day-Ahead Real Time Rate and Pilot to Evaluate Customer Understanding and Supporting Technology	Application 20-10-011 (Filed October 23, 2020)

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Pursuant to Rule 11.6 of the Commission's Rules of Practice and Procedure, Pacific Gas & Electric Company (PG&E) moves for a Ruling extending the dates in the schedule adopted in the Assigned Commissioner's Amended Scoping Memo issued on December 17, 2021. The Amended Scoping Memo, page 4, identifies the following area as one of two for the remainder of this case, and establishes a procedural schedule for it:

> 1. How should the MGCC be calculated to ensure PG&E's DAHRTP [Day-Ahead Real Time Pricing] rate accurately reflects hourly variations to the marginal costs of serving incremental load?

On page 5, the Amended Scoping Memo sets the procedural schedule applicable to these issues in 2022, starting with submission of the MGCC Study on January 18, 2022.[1]

PG&E and the parties with experts[2] working on the MGCC study (Study) have been mindful of the need to complete the Study in a timely manner to enable a decision on the MGCC methodology to issue sufficiently in time to implement the Real Time Pricing Schedule B-EV rate (DAHRTP-CEV) based on PG&E's testimony proposal. The MGCC study participants

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1 The Amended Scoping Memo dates for submission of the MGCC study, service of Direct Testimony, service of Rebuttal testimony, and the March 4, 2022 date for motions for evidentiary hearing are the same as contained on page 40 of D.21-11-017, except the scope for testimony and hearings now includes the export compensation mechanism.

2 Parties involved in the MGCC study (the MGCC Study Participants) are the California Large Energy Consumers Association (CLECA), Small Business Utility Advocates (SBUA), Public Advocates Office at the California Public Utilities Commission (Cal Advocates), and Enel X, as well as PG&E.

(Study participants) have been working diligently to complete the analyses in time to submit the MGCC study by January 18, 2022. However, the Study cannot be completed by January 18, 2022 and therefore we request an eight-week extension to the procedural dates in the Amended Scoping Memo for MGCC Study issues.[3]

I. THE RECORD WOULD BE WELL SERVED BY AN EXTENSION TO COMPLETE THE MGCC STUDY AND REACH POSSIBLE RESOLUTION ON REMAINING ISSUES, BASED ON THE BEST AVAILABLE DATA

The Study participants have prepared a Status Report on the progress that has been made to analyze and resolve various issues for MGCC and RTP. The Status Report that is attached to this pleading identifies analyses remaining to be done, and the issues that those analyses affect. That status report is current as of December 29, 2021, but work continues on the data and unresolved questions. The Study participants estimate that a minimum of an additional eight weeks beyond the current scheduled date of January 18, 2022 is required to conduct the required data analyses and report preparation to answer remaining questions about the MGCC methodology that would best allocate the annualized MGCC value approved in A.19-11-019 to hours of the year for the MGCC component of the RTP rate. However, the Study participants note that an eight-week extension would still represent a shortened schedule for submission of the Study after the Energy Division delivered all data to Study participants (approximately four months from when the Energy Division completed its data delivery[4]), compared to the five to six-month estimate specified in the DAHRTP-CEV Stipulation[5].

Delays in receipt of the necessary data have contributed significantly to the need for an extension. A suggested schedule for the presentation of Study results and resulting MGCC

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[3] All Parties that are actively involved in the MGCC Research Study support this extension request. And on December 23, 2021, PG&E sent an e-mail to the service list in A.20-10-011 informing them that PG&E would request an 8-week extension for the MGCC related procedural dates in the December 17, 2021 Amended Scoping Memo.

[4] The Energy Division completed its delivery of requested data to the Study participants on November 23, 2021, and the Study participants are requesting to update the MGCC study submission date to March 15, 2022, which would grant them slightly less than four months total to complete the study.

[5] The Stipulation is Exhibit PG&E-20.

proposals had been included in PG&E Exhibit 22 in A.20-10-011.[6] That schedule had assumed that necessary data would be received from Energy Division by August 2021, to allow sufficient time to submit the Study for presentation January 18, 2022. However, initial data was not received until September 24, with additional necessary data received on November 9, November 17 and November 23 of 2021. Thus, the final set of data necessary for the Study was not received until almost three months after the original date specified in the DAHRTP-CEV Stipulation. As anticipated, the amount of data is massive with several different data sets involved. As discussed in the Status Report, irregularities and gaps in the data sets have added unanticipated complexity to the data analysis. The MGCC Study participants have been working hard to try to deliver the MGCC study by January 18, 2022, and have been meeting approximately weekly since mid-October, 2021. Recently, the MGCC Study Participants have determined that adequate completion of the MGCC Study requires eight additional weeks.

PG&E and the other MGCC Study participants strongly recommend that they be allowed to complete the remaining analyses and work identified in the Status Report, which will result in many beneficial outcomes and robust, data-driven analyses that cannot be completed if the current deadline (January 18) is maintained. For instance, the Study participants have compared many different load metrics to forecasted SERVM system reliability data and historical CAISO events and have settled on net load[7] with a temperature adjustment as exhibiting the best fit with the observed data, but they have not yet developed a functional price curve to set hourly generation capacity prices based on net load plus a temperature adjustment.[8] The MGCC Study group was only able to obtain scarcity prices used in the CAISO's operations at the end of

[6] The CPUC's final decision, D.21-11-017, set a schedule for presentation of the MGCC study and for service of opening, reply and rebuttal testimony.

[7] Net load is system-level metered load less utility-scale wind and solar generation. This is different than PG&E's original proposal to use "adjusted net load" (ANL) to set the generation capacity prices in the DAHRTP proceeding. The Study group analyzed ANL and many other metrics, but found that ordinary net load with an adjustment for imports (the temperature adjustment) showed the best fit with various indicators of capacity shortfall and system reliability risk.

[8] The Study parties have also agreed on four system reliability metrics from the SERVM data to use to develop the MGCC functional price curve, and it appears the price curve is likely.

December.[9] This is a promising data source for weighting the different SERVM reliability metrics using threshold prices from the CAISO's daily system operations to develop a functional price curve for MGCC, but the analysis will require more time. The Study participants have also agreed in concept but require more time to develop dynamic price adders that would reflect real time (day-ahead) CAISO alert, warning, and emergency (AWE) events and that have prices that accurately represent system risk relative to the net load plus temperature price signal. Finally, the additional time would allow the Study participants to model customer annual bill volatility of a typical medium and large commercial customer with on-site battery storage, and their ability to manage their generation charges even during a year with especially high system risk and costs. This is the only part of the Study that will analyze the rate from the perspective of a prospective (theoretical) customer to confirm that the rate's variability lies within the range that customers can reasonably respond to if they have appropriate enabling technologies.

Ultimately, a robust MGCC study will provide data-driven analyses of expected inter-annual variability in the capacity and overall generation portions of customer bills, the alignment between CAISO Alerts, Warnings and Emergencies (AWEs) and various load metrics, the impact of including CAISO Alerts, Flex Alerts, and Restricted Maintenance Operations (RMO) events in the MGCC signal, and the appropriate functional form of the load-based MGCC signal.

If the Amended Scoping Memo schedule is not extended, the MGCC Report will have crucial data/analyses missing and important questions unanswered. Leaving some questions unanswered would add unnecessary complex fact finding to the hearing and final decision by the Commission in order to resolve essential features of the DAHRTP rate. The MGCC Study Participants are also concerned that due to the large amount of data to be considered, a rushed study could contain errors which would have to be resolved later, possibly leading to delays that affect the final rollout of the RTP BEV rate and the GRC II pilots. PG&E and the other MGCC

[9] Energy Division omitted all reserves shortfall pricing data from its SERVM run outputs, so while the SERVM runs provide important reliability and load metrics they do not provide information of how to price different reliability events or metrics.

Study Participants maintain that in order to answer the question, *"How should the MGCC be calculated to ensure PG&E's DAHRTP rate accurately reflects hourly variations to the marginal costs of serving incremental load"*, the requested eight-week extension should be granted to the dates shown in the following table:

Item	Amended Scoping Memo Deadline	8-week Extension Deadline,
MGCC (marginal generation capacity cost) Study filed and served in both A.20-10-011 and A.19-11-019	January 18, 2022	March 15, 2022
PG&E-hosted Meet-and-Confer session on MGCC Study	February 2022	Late March/early April 2022
Direct Testimony served. PG&E shall include a meet-and-confer report in its Direct Testimony	February 21, 2022	April 18, 2022
Motions for Evidentiary Hearing related to MGCC issues filed and served	March 4, 2022	April 29, 2022
Rebuttal Testimony served	March 11, 2022	May 6, 2022
Status Conference held;	March 25, 2022	May 15, 2022
Evidentiary Hearing on MGCC and export compensation issues held (if necessary)	April 19 to 22	June 14 to 17, 2022
Opening Briefs filed and served	May 2022	July 2022
Reply Briefs filed and served	June 2022	August 2022
Proposed Decision on Phase 2 of A.20-10-011 issued	Q3 2022	Q4 2022

A decision in Q4 2022 itself would not delay the implementation of the DAHRTP-CEV optional rate beyond 2023 as discussed in PG&E's testimony. Resolution of the MGCC issues is necessary for development of the customer tool that calculates the hourly RTP price, but the schedule above would allow the customer tool to be developed in time to roll out RTP for Electric Schedule BEV in 2023. PG&E notes that the eight-week extension does not affect the schedule for the billing system changes needed for implementation.[10]

Wherefore, PG&E and the other MGCC Study Participants respectfully request the ALJ to issue a ruling adopting the eight-week extension dates shown above, on an expedited basis.

II. CONCLUSION

For the reasons discussed in this motion, the Presiding ALJ should promptly issue a ruling to grant the requested extension in due dates set forth above. PG&E will also file a motion to shorten time for responses to this motion to enable the presiding administrative law judge to act expeditiously to grant the relief requested in this pleading, since time is of the essence.

Respectfully Submitted,

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Dated: January 6, 2022

[10] See, Ex. PG&E-3, page 3-1, which states that the DAHRTP-CEV rollout timeline is dependent on the timing of the replacement project for PG&E's Complex Billing System.

MGCC STUDY STATUS REPORT

DECEMBER 29, 2021

I. MGCC Study Status Report December 29, 2021

This MGCC Study Status Report is the opinion of the individuals (subject matter experts, or SMEs) who have collaborated in the study on behalf of their respective organizations. As the Status Report reflects their opinion regarding incomplete analysis, and further that the analysis has not been shared for review within their organizations, any opinions expressed should be considered useful only for the purpose of understanding the current status of the MGCC Study. The Status Report should not be construed to represent official opinions, findings, or recommendations of any of the Parties participating in the MGCC Study or any Settling Party.

The purpose of this MGCC Study Status Report is to provide the Presiding Administrative Law Judges and the parties on the service lists in A.20-10-011 and A.19-11-019 with information on the work that the SMEs have performed on the MGCC Study to date, the analyses and work that remains to be done, the questions about MGCC methodology for the Real Time Pricing rate that the remaining work will help answer, and the importance of sufficient time to quality check the quantitative aspects of the MGCC Study.

A. Access to Energy Division Data

1. Chronology

The MGCC Stipulation in A.20-10-011, Ex. PG&E-20, stated that, "The Stipulating Parties would start work on the Study as soon as Energy Division makes the SERVM data available. Thereafter, the estimate for completion of the Study is 5 to 6 months." The MGCC Study schedule outlined in Exhibit PG&E-22 indicated that the parties anticipated that the study would begin in August 2021 and conclude in December 2021.

However, in August the Study participants learned that Energy Division staff was unable to deliver the requested data at that time. Instead, while waiting for availability of data from Energy Division, PG&E used internal SERVM test runs in order to develop familiarity with the variables that might be provided by Energy Division. The Study participants also collected and refined relevant historical datasets, building on data used by the Stipulating Parties in testimony filed in Dockets A.20-10-011 and A.19-11-019.

PG&E staff received the first data delivery from Energy Division on September 24th. Energy Division provided 10 SERVM cases (out of 100) that were available on an hourly basis for the 2022, 2026, and 2030 forecast years. At this time, Study participants believed those 10 cases represented the 10 highest expected unserved energy (EUE) cases for each forecast year, although that proved to be an incorrect understanding.

On October 20th and 25th, PG&E made supplemental requests to Energy Division for an output variable that was omitted from the original response, plus a request for summary data for all 100 2022 cases and input data. The output variable was provided on November 9th.

On November 15th, Energy Division notified us that the requested summary data for all 100 2022 cases could not be located. Instead, we were provided the 100 cases with summary data for 2026. These were delivered on November 17th.

On November 23rd, Energy Division notified us that they had located an annual summary data file for 100 2022 cases, and provided those data, but these cases were from a high-stress sensitivity run, not the data that correspond to the 10 hourly cases.

Therefore, the Study participants did not actually receive the full datasets originally requested until November 23, which implies a completion date of April 22 using the more aggressive option under the original 5-6 month estimated timeline. Study participants recognize that they were able to complete some analyses using the incomplete datasets provided earlier, and therefore can commit to finalizing the report only four months after receipt of all data, i.e., in March 2022. That is an eight-week delay from the current schedule of January 18th.

2. Summary

The Schedule outlined in Exhibit PG&E-22 turned out to be infeasible primarily because the delivery of data from Energy Division was delayed nearly three months. The SMEs appreciate Energy Division's provision of data in request to their responses given Energy Division's significant workload with the IRP and IDER proceedings, among others. However, only after receiving and examining the final dataset in late November did the Study participants have confidence that they had received the best-available data from Energy Division that could be used to complete the study. Study participants have been working diligently since receiving the first, incomplete data in September, and now believe that the final report can be produced in a shorter period than the 5-6 months originally estimated, but no earlier than mid-March, 2022.

B. Challenges Presented by Energy Division Data

The SERVM data provided by Energy Division had been used to produce the 2021 Transmission Planning Process inputs. However, there were several limitations to the data, some of which are discussed in this Status Report.

First, the hourly data cases do not represent an ideally constructed statistical representation of the relationship between reliability, load, and generation.

- Each case represents the average of 50 stochastic model iterations. While suitable for many purposes, this averaging conceals a certain amount of statistical variation that would be useful for analysis.
- Energy Division retained hourly data for only ten of the 100 cases for each forecast year.
- Energy Division confirmed by email on November 23 that the ten cases retained are not the cases with the highest Expected Unserved Energy (EUE); it is unclear how those cases were selected.
- For the 2022 forecast year, two of the ten cases included very unusual results that do not appear in any of the 2026 or 2030 hourly cases, nor in the summary results from the 100 2022 high-stress cases. For reasons that will be discussed in the final report, the Study participants have decided to exclude these two cases from the analysis.

- For the 2022 forecast year, the summary data for the 100 cases are from a different (high-load, high-stress) model run than the ten supplied hourly cases. Energy Division has been unable to locate the 100-case 2022 run that more closely aligns with the hourly 2022 data provided earlier. This makes it difficult to understand how the hourly cases relate to the full 100 case SERVM analysis.

Second, Energy Division did not provide all the data that could have been useful for completing the study. Specifically, Energy Division redacted Operating Reserve Demand Curves and all pricing data from the output files due to concerns about its validity. The Study participants understand the concerns of Energy Division, but this decision has resulted in a need to conduct further research to obtain alternate references.

C. Access to and Issues With CAISO Data

The MGCC stipulation noted, "It would also be valuable to the Study to obtain more detailed information from CAISO regarding the standards that it applies to initiate an Alert, Warning or Emergency (AWE) event, both in general and with respect to historical events." Study participants requested this information during a conference call on July 13, 2021, but have been unable to obtain additional information from CAISO beyond what is published on its website.

In addition, the list of Alerts, Warnings and Emergencies published by CAISO[1] turned out to be incomplete (e.g., missing the time of the announcement, which affects whether an announcement is classified as day-ahead or day-of) or inconsistent with some of the press releases and other information published by CAISO. The Study participants have used multiple information sources to check the data in the AWE list and ensure its accuracy for use in the Study.

D. Areas of Consensus Among Study Participants

The Study participants have reached consensus on a number of issues.

1. General MGCC Price Design and Operation

The MGCC Price should be set using a formula that allocates MGCC marginal cost revenues to the various hours in the year using an adder for day-ahead (DA) CAISO Alerts, Warnings and Emergencies (AWE) and a measure of forecasted net loads. For most hours of the year, this formula should result in a MGCC value of (or very nearly) zero. The MGCC portion of the hourly price would then be added to the DA energy price for the hour (adjusted for losses) and the Revenue Neutral Adder to obtain the generation component of the RTP rate.

2. PG&E will communicate to participants late in the afternoon of the day before operating day, either with pricing information or a notification that the pricing information will be delayed or potentially revised.

Study participants are still discussing the optimal timing of notifications, since a significant number of Flex Alerts have historically been issued in the early evening, generally after having issued an RMO. There is therefore a tradeoff between capturing the most CAISO Flex Alerts and customer convenience.

[1] http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf#search=AWE

3. MGCC Price Design Components

The Study participants have reached consensus on the following details regarding the components of the MGCC portion of the DAHRTP rate.

1. **DA Flex Alert or Alert (DA FA/A) adder**
    a. No minimum or maximum number of events
    b. Southern California (SoCal)-only events should be excluded
    c. Applies to all hours called by CAISO
2. **DA RMO adder** – Study participants are continuing analysis to determine if an RMO adder should be included. If an RMO adder is included, Study participants have reached consensus on the following:
    a. No minimum or maximum number of events
    b. SoCal-only events should be excluded
    c. Smaller than the DA FA/A adder
    d. Limited to peak and part-peak hours (some RMO events cover most or all of a day)
3. **Adjusted Net Load definition** – Study participants have reached consensus that ANL should be defined as Net Load with a temperature adjustment (using weather stations at Phoenix Airport (PHX) and Seattle-Tacoma Airport (SEA), which were also used in the Marginal Energy Cost (MEC) model developed by PG&E in its 2020 GRC II testimony).
    a. The Study participants used both historical and modeled forecast data to determine the functional form. The Study participants agree that historical data provide more information regarding how reliability events occur because CAISO AWE events in the historical record indicate precisely when reliability events actually occurred. SERVM forecast indicators are useful, but less suitable, because they may overlook operational issues that CAISO considers in practice as well as only providing statistical indications of the probability that an event might occur, especially as only 50-scenario averaged cases were made available to Study participants.
    b. Study participants evaluated seven different load metrics such as PG&E's current Adjusted Net Load function (used in PG&E's MEC model and originally proposed by PG&E to develop the hourly capacity costs), gross load, and several other combinations, including the selected net load with temperature adjustments.
    c. Study participants examined concordance between the seven candidate load metrics with CAISO AWE events in historical record from 2010-2021, with a special focus on 2017-2021 period. The temperature correction (using PHX and SEA weather stations) generally improved the net load metric.
    d. Study participants examined concordance between the seven candidate load metrics with EUE and reserve shortfalls in forecast SERVM data, using the hourly cases for 2022 and 2026 forecast years. For these datasets the temperature correction did not improve the net load metric, but neither did it cause the net load metric to perform significantly worse.

4. **Adjusted net load functional form –** Study participants have not completed development of the function that calculates a grid stress metric based on Adjusted Net Load but have reached the following conclusions.
    a. The function should be developed using a combination of several reliability metrics available in SERVM output, including Expected Unserved Energy (EUE), demand response (DR), and two measures of reserve shortfalls. Historical data are not as useful because (i) they do not include the same generation resources (in particular, solar and battery resources) as are anticipated during the duration of the RTP pilots in A.20-10-011 and Al19-11-019, and (ii) they do not provide a statistical representation of the relationship between ANL and reliability.
    b. For each of the reliability metrics, the functional form increases more slowly than linear at low to moderate load levels and faster than linear at very high load levels (i.e. it has a sigmoidal or exponential/power law shape).
    c. EUE has a steeper slope and becomes significant only at higher load levels than reserve shortfalls, with DR falling between these two extremes.
    d. There should be a cap on hourly capacity prices to reduce the impact of outlier events on customer bills and acceptance.

4. Investigation of Inter-Annual Variability

The Study participants have also made progress on the evaluation of potential constraints on inter-annual variability. The RTP price will be designed to recover the costs PG&E incurs to serve marginal load. Because those costs vary from year to year, but the revenue requirement for MGCCs does not, inter-annual variability presents some challenges for rate design from equity and cost recovery perspectives. The Study participants have reached consensus on the following points.

1. The overall RTP price should have some inter-annual variability in total bill, but less than the inter-annual variability obtained from PG&E's original proposal.
2. The variability in the ANL load metric function by itself should be explored using SERVM data because those data are based on forecast generation and load characteristics. However, calculated variability based on SERVM data is likely a lower bound, since the SERVM data represent averages over 50 iterations, thus does not account for all sources of variability in the real CAISO grid.
3. The variability in the FA/A and RMO adders is being explored using historical data because it is not possible to forecast AWE events and such events do not appear in the SERVM datasets.
4. The total variability can only be generally estimated, because of limitations with the SERVM data as well as the changing characteristics of CAISO-called AWE events.
5. Total inter-annual variability in a modeled MGCC component over recent years, and the total generation component (including MEC and RNA) can be compared to historical variability in the MEC component by itself, and to prices for Resource Adequacy. These comparisons can be useful as benchmarks, but not targets for the final MGCC design.

E. Areas of Continuing Work

There are a number of issues that are not yet resolved, as well as practical steps that should be completed prior to completing the MGCC Study Report. Study participants consider it highly likely that remaining data analysis and discussion will lead to resolution of the remaining issues. If Study participants cannot reach consensus on any remaining issues, it is likely that those issues will be clearly defined for resolution by the Commission.

1. MGCC Price Design Components

So far, the Study participants have not yet agreed on an MGCC price formula that allocates MGCC marginal cost revenues to the various hours. As discussed in Section D.3 above, the Study participants have agreed on a number of principles and design features that differ from the original proposals of the parties. In order to complete the MGCC price formula consistent with the consensus so far, additional work is required. Using an MGCC price formula that is not based on a full exploration and explanation of the issues described below could in inducing inefficient participant response to price signals, potentially inconsistent with other programs (e.g., demand response).

Considering the progress described in Section D.3 above, the Study participants are working to analyze and resolve these remaining issues.

1. **DA Flex Alerts or Alert (DA FA/A) adder**
    a. The amount of MGCC cost that should be allocated to this component
    b. The number of events per year that should be assumed when evaluating the impact of the rates on customer bills, including for marketing and education
2. **DA RMO adder** – Study participants are continuing analysis to determine if an RMO adder should be included. If an RMO adder is included, Study participants have agreed that the hours should be limited to the peak and shoulder-peak,[2] and are working to analyze:
    a. The amount of MGCC cost that should be allocated to this component
    b. The number of events per year that should be assumed
    c. Whether any types of RMO events should be excluded beyond SoCal-only
3. **Temperature-adjusted net load function**
    a. The amount of MGCC cost that should be allocated to this component
    b. The relative cost of (or value of avoided) EUE, DR, and reserves shortfalls used to develop the overall grid stress metric
    c. The functional form relating temperature-adjusted net load to the grid stress metric
    d. Any cap on the hourly MGCC price
    e. The method for converting the functional form in terms of SERVM data into a functional form that applies to historical, and forecast data during the operation of the pilot

2. Investigation of Inter-Annual Variability

The MGCC Study is evaluating inter-annual variability because while the RTP price will be designed to recover the costs PG&E incurs to serve marginal load, the likely revenue recovery will vary from year to year. The Study participants view balancing the collection of the revenue requirement for MGCCs with the inter-annual variability in drivers of the MGCC price as important to achieving equity between

[2] RMOs can be set for full 24-hour or multi-day periods, as they relate to generation and transmission facilities that may have significant return-to-service constraints. Such constraints would not apply to customers enrolled in the pilot.

participants and non-participants in a defensible manner and creating manageable solutions to ensure full cost recovery. In addition, customers may be more likely to join the pilot if it can be demonstrated that load-shifting may be able to mitigate the risk that generation charges would significantly exceed those under their OAT during a high-grid stress year.

Considering the progress described in Section D.4 above, the Study participants are working to analyze and resolve these remaining issues.

1. The desirable amount of total inter-annual variability, balancing the interest in tracking marginal costs against the complications of cost recovery and equity.
2. The scope (I.e., the metric used to evaluate) of inter-annual variability, considering the following alternatives:
    a. MGCC price
    b. MGCC plus Marginal Energy Cost (MEC) price
    c. Customer bill variability, which may be complicated to estimate due to assumptions regarding RTP-induced load shifting (demand charge and TOU period considerations would affect the bill)
3. The method for measuring and benchmarking inter-annual variability, including:
    a. Variability in RA prices over past 10 years as one possible benchmark
    b. Measuring variance in SERVM data (e.g., potentially using 90/10 percentiles in cases with only weather-induced load variations)
    c. Consideration of the impact of averaging across 50 iterations in each case
    d. Consideration of FA/A and RMO adder impacts
    e. Consideration of an approximate comparator to total variance from historical data, adjusting solar penetration in early years to current-year values.
4. Consideration of load forecast variation when interpreting findings

3. Production of Graphics and Text

The Study participants have begun a working draft of the report. However, relevant graphics and text for the areas of consensus are incomplete as it would be inefficient to produce those materials when they are subject to revision as additional issues are resolved.

Furthermore, each Study participant’s organization will conduct its own internal review and comment on the draft MGCC Study Report.

Completion of this work and review cannot be finished by January 18, 2022 and requires at a minimum, an eight-week extension to the schedule in the December 17, 2021 Amended Scoping Memo.

APPENDIX B – ATTACHMENT C

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 E)	Application No. 19-11-019 (Filed November 22, 2019)

DECLARATION OF ANH DONG IN SUPPORT OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON RESIDENTIAL STAGE 1 RTP PILOT COST ESTIMATES

I, Anh Dong, declare under penalty of perjury under the laws of the State of California that the following is true and correct to the best of my knowledge and belief:

1. I am a Senior Manager in the Pricing Products Department. My responsibilities include defining and implementing Information Technology (IT) solutions to build rate plans, helping customers better understand and manage their energy use and bills.

2. PG&E and Settling Parties[1] have reached a mutually acceptable outcome on the program design issues as presented in this GRC Phase II proceeding. This Settlement Agreement includes a Stage 1 RTP Pilot for residential customers on the E-ELEC rate (Residential Stage 1 RTP Pilot).

3. I am responsible for developing PG&E's estimates of Measurement and Evaluation and Program Administration costs contained in this declaration for the Residential Stage 1 RTP Pilot. I also participated in the development, during settlement negotiations, of the estimated costs for Marketing, Education and Outreach, and Incentives, set forth below.

4. The Residential Stage 1 RTP Pilot is the product of settlement and was not proposed in PG&E's opening testimony. Therefore, I provide the following information on certain

[1] Agricultural Energy Consumers Association (AECA), California Large Energy Consumers Association (CLECA), California Solar and Storage Association (CALSSA), Enel X North America, Inc. (ENEL X), Energy Producers and Users Coalition (EPUC), Federal Executive Agencies (FEA), PG&E, Public Advocates Office at the CPUC (Cal Advocates), Small Business Utility Advocates (SBUA), and Ohm Connect.

elements of costs for the Residential Stage 1 RTP Pilot that are incremental to the high estimate of the costs associated with PG&E's original RTP Pilot proposal (that did not include a pilot of a residential RTP rate as does the Settlement).[2]

The following four categories of costs will be recorded to the Dynamic and Real Time Pricing Memorandum Account (DRTPMA) and are estimated as follows:

a.	Marketing Education & Outreach	$350,000
b.	Incentives	$706,250
c.	Measurement and Evaluation	$500,000
d.	Program Administration	$250,000[3]

5. The estimated Measurement and Evaluation costs are based on PG&E's experience in other matters requiring measurement and evaluation, taking into account the unique nature of both the C&I and Residential Stage 1 RTP Pilots. The Program Administration cost estimate is PG&E's best estimate based on my experienced professional judgement.

6. The amount of expected Marketing, Education, and Outreach and the level of Incentives the product of settlement negotiations; based on my experience, I have provided cost estimates that reflect those agreements and believe that PG&E can manage and execute these elements of the Residential Stage 1 RTP Pilot within these negotiated costs.

7. I am not able to estimate, at this time, the cost of whatever bill protection payments may need to be paid to Residential Stage 1 RTP Pilot participants pursuant to the Settlement's terms, because the real time pricing component of the piloted E-ELEC RTP rate will be dependent on future volatility in the CAISO hourly day-ahead (DAM) market prices, which PG&E cannot predict, nor can PG&E predict how participating Residential Stage 1 RTP Pilot customers will modify their usage patterns in response to unknowable future hourly RTP prices in the DAM.

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[2] The total cost estimate for the C&I Stage 1 RTP Pilot proposal was $7.776 million to $11.096 million (A.10-11-019, Exhibit (PG&E-RTP-1), p. 5-25, Table 5-5). The cost estimate for the Customer Research Study for residential and agricultural customers was $400,000 to $700,000 (PG&E-RTP-1, p. 1-45, lines 15 and 16).

[3] Cost is for one added contractor or FTE to provide operational support.

7. The additional costs presented here are incremental to the costs estimated in PG&E's initial C&I Stage 1 Pilot proposal (provided in Footnote 2) submitted in its supplemental testimony served on March 29, 2021 (Exhibit PG&E-RTP-1). All costs, including the amount of bill protection payments for bundled residential customers participating in the residential RTP pilot, will be tracked in the DRTPMA for recovery in a future application and testimony, and recovered pursuant to the Settlement Agreement's terms as described in Section V.B.16. These estimates of incremental cost may not be comprehensive in that other costs might later emerge as being necessary and reasonable for operating the Residential Stage 1 RTP Pilot agreed to in the Settlement. The above estimates assume adoption of the Settlement Agreement's Residential Stage 1 RTP Pilot in its entirety without modification.

8. I declare under penalty of perjury under the laws of the State of California that the statements made above are true and correct to the best of my knowledge and belief.

Executed this ____ day of January, 2022 at San Francisco, California

____

Anh Dong

Senior Manager, Pricing Products